ERCOT Nodal Protocols

Updated: August 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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Updated: April 1, 2008

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1 OVERVIEW

1.1 Summary of the ERCOT Protocols Document

(1) The Electric Reliability Council of Texas (ERCOT) Protocols, created through the collaborative efforts of representatives of all segments of Market Participants, means the document adopted by ERCOT, including any attachments or exhibits referenced in these Protocols, as amended from time to time, that contains the scheduling, operating, planning, reliability, and settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. To determine responsibilities at a given time, the version of the ERCOT Protocols in effect at the time of the performance or non-performance of an action governs with respect to that action. These Protocols are intended to implement ERCOT's functions as the Independent Organization for the ERCOT Region as certified by the Public Utility Commission of Texas (PUCT) and as the "Program Administrator" appointed by the PUCT that is responsible for carrying out the administrative responsibilities related to the Renewable Energy Credit Program as set forth in subsection (g) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. Market Participants, the Independent Market Monitor (IMM), and ERCOT shall abide by these Protocols.

(2) The ERCOT Board, Technical Advisory Committee (TAC), and other ERCOT subcommittees authorized by the Board or TAC ("ERCOT's Committees") or ERCOT staff may develop polices, guidelines, procedures, forms, and applications for the implementation of and operation under, these Protocols and to comply with applicable rules, laws, and orders of a Governmental Authority. A policy, guideline, procedure, form, or application described above is an "Other Binding Document" if it meets the requirements set forth below. ERCOT shall post all Other Binding Documents to a part of the MIS Public Area reserved for posting Other Binding Documents. "Other Binding Documents" means:

(a) The Commercial Operations Market Guide, the Competitive Metering Guide, the Load Profiling Guide, the Operating Guides, the Operating Procedures, the Retail Market Guide, the Settlement Metering Operating Guide, the Power System Planning Charter and Process, the Texas SET Guides, the Texas Market Test Plan, and the ERCOT Creditworthiness Standards; and

(b) The policies, guidelines, procedures, forms, and applications satisfying all the requirements listed below:

(i) Before the policy, guideline, procedure, form, or application takes effect, ERCOT must e-mail it to all affected registered Market Participants and post it to the part of the MIS Public Area reserved for posting of Other Binding Documents. ERCOT must use reasonable efforts to e-mail and post the policy, guideline, procedure, form, or application at least 30 days before it takes effect, but ERCOT must e-mail and post the policy, guideline, procedure, form, or application at least 15 Business Days before it takes effect, unless ERCOT reasonably determines that an urgent circumstance necessitates a shorter notice period or the ERCOT Board approves a shorter notice period.

(ii) If either the e-mail or posting under Section 1.1(2)(b)(i) occurs less than 30 days before the policy, guideline, procedure, form, or application takes effect, ERCOT must include in the e-mail and posting an explanation of why it was not able to give 30 days' advance notice before the policy, guideline, procedure, form, or application takes effect.

(iii) ERCOT must label the policy, guideline, procedure, form, or application at the top of its first page with the words "Other Binding Document under Section 1.1 of the Protocols."

(iv) The policy, guideline, procedure, form, or application must expressly state how long it will be in effect.

(3) Any revision of an Other Binding Document must follow the revision process set forth in that Other Binding Document. If an Other Binding Document does not specify a revision process, the requirements of Section 1.1(2)(b)(i) through (iv) apply to any revision of that Other Binding Document. To the extent that Other Binding Documents are not in conflict with these Protocols or with an Agreement to which it is a party, each Market Participant, the IMM, and ERCOT shall abide by the Other Binding Documents.

(4) Taken together, these Protocols and the Other Binding Documents constitute all of the "scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by the independent system operator in ERCOT," as that phrase is used in subsection (j) of the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2003) (PURA), Essential Organizations, that bind Market Participants.

(5) Except as provided below, if the provisions in any attachment to these Protocols or in any of the Other Binding Documents conflict with the provisions of Protocols Section 1, Overview, through Section 21, Process for Protocols Revision, Section 23, Texas Plan Team - Retail Market Testing, through Section 24, Point to Point Communications, then the provisions of Protocols Section 1 through Section 21, Section 23 through Section 24 prevail to the extent of the inconsistency. If any provision of any Agreement conflicts with any provision of the Protocols, the Agreement prevails to the extent of the conflict. Any Agreement provision that deviates from the standard form for that Agreement in Section 22 must expressly state that the Agreement provision deviates from the standard form in Section 22. Agreement provisions that deviate from the Protocols are effective only upon approval by the ERCOT Board on a showing of good cause.

(6) These Protocols are not intended to govern the direct relationships between or among Market Participants except as expressly provided in these Protocols. ERCOT is not responsible for any relationship between or among Market Participants to which ERCOT is not a party.

1.2 Functions of ERCOT

(1) ERCOT is the Independent Organization certified by the PUCT for the ERCOT Region. The major functions of ERCOT, as the Independent Organization, are to:

(a) Ensure access to the ERCOT Transmission Grid and Distribution Systems for all buyers and sellers of electricity on nondiscriminatory terms;

(b) Ensure the reliability and adequacy of the ERCOT Transmission Grid;

(c) Ensure that information relating to a Customer's choice of Retail Electric Provider in Texas is conveyed in a timely manner to the persons who need that information; and

(d) Ensure that electricity production and delivery are accurately accounted for among the All-Inclusive Generation Resources and wholesale buyers and sellers, and Transmission Service Providers and Distribution Service Providers, in the ERCOT Region.

(2) ERCOT is the Control Area Operator for the ERCOT interconnection and performs all Control Area functions as defined in the Operating Guides and the North American Electric Reliability Corporation (NERC) policies.

(3) ERCOT is the PUCT-appointed Program Administrator of the Renewable Energy Credits Program.

(4) These Protocols are intended to implement the above-described functions.

(5) In exercising any functions related to deployment of energy or Ancillary Service as described in these Protocols, ERCOT acts only as an agent on behalf of the various Market Participants in fulfilling these duties, subject to the settlement process in these Protocols. All references in these Protocols to provision, procurement, purchase, deployment, or Dispatch of energy or Ancillary Service or any other similar action must be interpreted to mean that ERCOT is taking such action on behalf of Market Participants as an agent. Nothing in these Protocols may be construed as causing ERCOT to take title to any energy or Ancillary Service or to cause TSPs, DSPs, or Resources to transfer any control of their facilities to ERCOT. In the exercise of its sole discretion under these Protocols, ERCOT shall act in a reasonable, nondiscriminatory manner.

(6) ERCOT may not profit financially from its activities as the Independent Organization in the ERCOT Region. ERCOT may not use its discretion in the procurement of Ancillary Service capacity or deployment of energy to influence, set or control prices.

1.3 Confidentiality

1.3.1 Restrictions on Protected Information

Section 1.3, Confidentiality, applies to Protected Information disclosed by a Market Participant to ERCOT or the Independent Market Monitor (IMM) or by ERCOT to a Market Participant or the IMM. ERCOT, the IMM, or any Market Participant ("Receiving Party") may not disclose Protected Information received from one of the others ("Disclosing Party") to any other Entity except as specifically permitted in this Section and in these Protocols. A Receiving Party may not use Protected Information except as necessary or appropriate in carrying out its responsibilities under these Protocols. To disclose means to directly or indirectly disclose, reveal, distribute, report, publish, or transfer Protected Information to any party other than to the Disclosing Party.

1.3.1.1 Items Considered Protected Information

Subject to the exclusions set out in Section 1.3.1.2, Items Not Considered Protected Information, "Protected Information" is information containing or revealing any of the following:

(a) Base Points, as calculated by ERCOT;

(b) Bids, offers, or pricing information identifiable to a specific QSE or Resource;

(c) Status of Resources, including outages, limitations, or scheduled or metered Resource data;

(d) Current Operating Plans;

(e) Ancillary Service Trades, Energy Trades, Capacity Trades, and Ancillary Service Schedules identifiable to a specific QSE or Resource;

(f) Dispatch Instructions identifiable to a specific QSE or Resource, except for RUC commitments and decommitments as provided in Section 5.5.3, Communication of RUC Commitments and Decommitments;

(g) Raw and Adjusted Metered Load data (demand and energy) identifiable to a specific QSE or Customer;

(h) Settlement Statements and Invoices identifiable to a specific QSE;

(i) Aggregated raw and Adjusted Metered Load data (demand and energy), and number of Electric Service Identifiers (ESI IDs) identifiable to a specific Load Serving Entity (LSE);

(j) Information related to generation interconnection requests, to the extent such information is not otherwise publicly available;

(k) Resource-specific costs, design and engineering data;

(l) Congestion Revenue Rights (CRR) credit limits, the identity of bidders in a CRR Auction, or other bidding information identifiable to a specific CRR Account Holder;

(m) Renewable Energy Credit (REC) account balances;

(n) Credit limits identifiable to a specific QSE;

(o) Any information that is designated as Protected Information in writing by Disclosing Party at the time the information is provided to Receiving Party except for information:

   (i) submitted to or collected by ERCOT under the Protocols or Other Binding Documents; or

   (ii) provided to ERCOT in support of a Reliability Must-Run (RMR) application under Section 3.14.1, Reliability Must Run;

(p) Any information compiled by a Market Participant on a Customer that in the normal course of a Market Participant's business that makes possible the identification of any individual Customer by matching such information with the Customer's name, address, account number, type of classification service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing record, or any other information that a Customer has expressly requested not be disclosed ("Proprietary Customer Information") unless the Customer has authorized the release for public disclosure of that information in a manner approved by the PUCT. Information that is redacted or organized is such a way as to make it impossible to identify the Customer to whom the information relates does not constitute Proprietary Customer Information;

(q) Any software, products of software, or other vendor information that ERCOT is required to keep confidential under its agreements;

(r) QSE, TSP, and DSP backup plans collected by ERCOT under the Protocols or Other Binding Documents;

(s) Direct Current (DC) Tie information provided to a TSP or DSP under Section 4.4.4, DC Tie Schedules; and

(t) Any Texas Standard Electronic Transaction (SET) transaction submitted by an LSE to ERCOT or received by an LSE from ERCOT. This paragraph does not apply to ERCOT's compliance with:

   (i) PUCT Rules on performance measure reporting;

(ii) these Protocols or Other Binding Documents; or

(iii) any TAC-approved reporting requirements.

(u) Mothballed Generation Resource updates and supporting documentation submitted pursuant to Section 3.14.1.9, Mothballed Generation Resource Time to Service Updates.

(v) For purposes of Capacity Demand Reserve Reporting, the unavailability of Switchable Generation Resources to the ERCOT System and supporting documentation submitted pursuant to paragraph (2) of Section 16.5.4, Maintaining and Updating Resource Entity Information, except for reporting the aggregate capacity.

(w) Information provided by Entities under Section 10.3.2.4, Reporting of Net Generation Capacity.

(x) Alternative fuel reserve capability and firm gas availability information submitted pursuant to Section 6.5.9.3.1, Operating Condition Notice, Section 6.5.9.3.2, Advisory, and Section 6.5.9.3.3, Alert; and as defined by the Operating Guides.

1.3.1.2 Items Not Considered Protected Information

(1) Notwithstanding the definition of “Protected Information” in Section 1.3.1.1, Items Considered Protected Information, the following items are not Protected Information even if so designated:

(a) Data comprising Load flow cases, which may include estimated peak and off-peak demand of any Load;

(b) RMR Agreements;

(c) Studies, reports and data used in ERCOT’s assessment of whether an RMR Unit satisfies ERCOT’s criteria for operational necessity to support ERCOT System reliability but only if they have been redacted to exclude Protected Information under Section 1.3.1.1;

(d) Status of RMR Units;

(e) Information provided to ERCOT in support of an “Application for Reliability Must Run (RMR) Status” according to Section 3.14.1, Reliability Must Run;

(f) Black Start Agreements;

(g) Signed generation interconnection agreements, and

(h) Any other information specifically designated in these Protocols as information to be posted to the MIS Public Area or MIS Secure Area that is not specified as information that is subject to the requirements of Section 1.3, Confidentiality.

(2) Protected Information that Receiving Party is permitted or required to disclose or use under the Protocols or under an agreement between Receiving Party and a Disclosing Party does not cease to be regarded as Protected Information in all other circumstances not encompassed by these Protocols or such agreement by virtue of the permitted or required Disclosure or use under these Protocols or such agreement.

1.3.2 Procedures for Protected Information

(1) The Receiving Party shall adopt procedures within its organization to maintain the confidentiality of all Protected Information. Such procedures must provide that:

(a) The Protected Information may be disclosed to the Receiving Party's directors, officers, employees, representatives, and agents only on a "need to know" basis;

(b) The Receiving Party shall make its directors, officers, employees, representatives, and agents aware of Receiving Party's obligations under this Section;

(c) If reasonably practicable, the Receiving Party shall cause any copies of the Protected Information that it creates or maintains, whether in hard copy, electronic format, or other form, to identify the Protected Information as such; and

(d) Before disclosing Protected Information to a representative or agent of the Receiving Party, the Receiving Party shall require a nondisclosure agreement with that representative or agent. That nondisclosure agreement must contain confidentiality provisions substantially similar to the terms of this Section.

1.3.3 Expiration of Confidentiality

(1) The following applies to the expiration of confidentiality for Protected Information:

(a) The Protected Information status of data specified under item (a) of Section 1.3.1.1, Items Considered Protected Information, expires seven days after the applicable Operating Day.

(b) The Protected Information status of part of the data specified under Section 1.3.1.1(b) expires 180 days after the applicable Operating Day, and ERCOT at that time shall make that part of the data available on the MIS Secure Area in a standard reporting format. That part of the data for which the Protected Information status expires and which is to be posted is as follows:

(i) Ancillary Service Offers by Operating Hour for each QSE for all Ancillary Service submitted for the DAM or any SASM;

(ii) The quantity of Ancillary Service offered by Operating Hour for each QSE for all Ancillary Service submitted for the DAM or any SASM; and

(iii) Energy Offer Curve prices and quantities for each Settlement Interval by Resource.

(c) The Protected Information status of data specified under Section 1.3.1.1(c) through (h) expires 180 days after the applicable Operating Day. One hundred eighty days after the Operating Day, ERCOT shall make the following information available on the MIS Secure Area in a standard reporting format:

(i) Ancillary Service Obligation and Ancillary Service Supply Responsibility for each QSE;

(ii) Actual metered Resource values for each QSE by Resource by Settlement Interval;

(iii) Complete Current Operating Plan data for each QSE snapshot on each hour; and

(iv) Adjusted Metered Load for each QSE by LSE, by Load Zone and by Settlement Interval, both from the initial settlement and all subsequent settlements. ERCOT shall post each subsequent Adjusted Metered Load within seven days after the subsequent settlement operation is finished. Data from the first posting and all subsequent settlement postings must remain accessible for at least 24 months after the Operating Day.

(c) The Protected Information status of data specified under Section 1.3.1.1(i) expires 365 days after the applicable Operating Day.

(d) REC account balances specified in Section 1.3.1.1(m) cease to be Protected Information three years after the REC Settlement period ends.

(e) The Protected Information status of data specified under paragraph 1.3.1.1(j) expires when the generation interconnection agreement is executed or a financial arrangement for transmission construction is completed with a TSP.

(f) The Protected Information status of data specified under Section 1.3.1.1(l) expires as follows:

(i) The Protected Information status of the identities of CRR bidders that become CRR Owners and the number and type of CRRs that they each own expire at the end of the CRR Auction in which the CRRs were first sold;

(ii) The Protected Information status of all other information identified in Section 1.3.1.1(l) expires six months after the end of the year in which the CRR was effective.

(2) Upon the expiration of the Protected Information status of any data as specified in paragraph (1) of Section 1.3.3, Expiration of Confidentiality, that data must be made available to the extent required under Section 12, Market Information System.

(3) Information that is no longer Protected Information, but not posted, including Dispatch Instructions, is available on request under the ERCOT Request for Records and Information Policy. Requested information must be provided within a reasonable timeframe. For Dispatch Instructions, the information may be requested with respect to a specific Resource, where applicable, and by service type and Settlement Interval or as integrated over each Settlement Interval for Dispatch Instructions with sub-Settlement Interval frequency.

1.3.4 Protecting Disclosures to the PUCT and Other Governmental Authorities

Any disclosure that a Receiving Party makes to the PUCT must be made under applicable PUCT rules. For any disclosure of Protected Information to the PUCT outside the scope of subsection (e) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance, the Receiving Party must file that Protected Information as confidential pursuant to subsection (d) of P.U.C. PROC. R. 22.71, Filing of Pleadings, Documents, and Other Materials. Before making a disclosure under order of a Governmental Authority other than the PUCT, the Receiving Party shall seek a protective order from such Governmental Authority to protect the confidentiality of Protected Information. Nothing in this Section authorizes any disclosure of Protected Information to the PUCT or other Governmental Authority; this Section merely creates requirements on disclosures that are authorized under other sections of these Protocols.

1.3.5 Notice Before Permitted Disclosure

Before making any disclosure under Section 1.3.4, Protecting Disclosures to the PUCT and Other Governmental Authorities, or under Section 1.3.6, Exceptions, Receiving Party shall promptly notify Disclosing Party in writing and shall assert confidentiality and cooperate with the Disclosing Party in seeking to protect the Protected Information from disclosure by confidentiality agreement, protective order, aggregation of information, or other reasonable measures. ERCOT is not required to provide notice to the Disclosing Party of disclosures made under Section 1.3.6(1)(b).

1.3.6 Exceptions

(1) The Receiving Party may, without violating Section 1.3, Confidentiality, disclose Protected Information:

(a) To governmental officials, Market Participants, the public, or others as required by any law, regulation, or order, or by these Protocols, but any Receiving Party must make reasonable efforts to restrict public access to the disclosed Protected Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(b) If ERCOT is the Receiving Party and disclosure to the PUCT of the Protected Information is required by ERCOT pursuant to applicable Protocol, law, regulation, or order; or

(c) If the Disclosing Party has given its prior written consent to the disclosure, which consent may be given or withheld in Disclosing Party's sole discretion; or

(d) If the Protected Information, before it is furnished to the Receiving Party, is in the public domain; or

(e) If the Protected Information, after it is furnished to the Receiving Party, enters the public domain other than as a result of a breach by the Receiving Party of its obligations under Section 1.3,; or

(f) If reasonably deemed by the disclosing Receiving Party to be required to be disclosed in connection with a dispute between the Receiving Party and the Disclosing Party, but the disclosing Receiving Party must make reasonable efforts to restrict public access to the disclosed Protected Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(g) To a TSP or DSP engaged in the ERCOT Transmission Grid or Distribution System planning and operating activities, provided that the TSP or DSP has executed a confidentiality agreement with requirements substantially similar to those in Section 1.3; or

(h) To a vendor or prospective vendor of goods and services to ERCOT so long as such vendor or prospective vendor:

(i) is not a Market Participant; and

(ii) has executed a confidentiality agreement with requirements substantially similar to those in Section 1.3;

(i) To the North American Electric Reliability Corporation (NERC) if required for compliance with any applicable NERC requirement, but any Receiving Party must make reasonable efforts to restrict public access to the disclosed Protected Information as reasonably possible; or

(j) To ERCOT and its consultants, the IMM, and members of task forces and working groups of ERCOT, if engaged in performing analysis of abnormal system conditions, disturbances, unusual events, and abnormal system performance. Notwithstanding the foregoing sentence, task forces and working groups may not receive Ancillary Service offer prices or other competitively sensitive price or cost information before expiration of its status as Protected Information, and each member of a task forces or working group shall execute a confidentiality agreement with requirements substantially similar to those in Section 1.3, prior to receiving any Protected Information. Data to be disclosed under this exception to task forces and working groups must be limited to clearly defined periods surrounding the relevant conditions, events, or performance under review and must be limited in scope to information pertinent to the condition or events under review and may include the following:

(i) QSE Ancillary Service awards and deployments, in aggregate and by type of Resource;

(ii) Resource facility availability status, including the status of switching devices, auxiliary loads, and mechanical systems that had a material impact on Resource facility availability or an adverse impact on the transmission system operation;

(iii) Individual Resource information including Base Points, maximum/minimum generating capability, droop setting, real power output, and reactive output;

(iv) Resource protective device settings and status;

(v) Data from Current Operating Plans; and

(vi) Resource Outage schedule information.

(2) Such information may not be disclosed to other Market Participants prior to 10 days following the Operating Day under review.

1.3.7 Specific Performance

It will be impossible or very difficult to measure in monetary terms the damages that would accrue due to any breach by Receiving Party of Section 1.3, Confidentiality, or any failure to perform any obligation contained in Section 1.3 and, for that reason, among others, a Disclosing Party affected by a disclosure or threatened disclosure is entitled to specific performance of Section 1.3. In the event that a Disclosing Party institutes any proceeding to enforce any part of Section 1.3, the affected Receiving Party, by entering any agreement incorporating these Protocols, now waives any claim or defense that an adequate remedy at law exists for such a breach.

1.3.8 Commission Declassification

After providing reasonable notice and opportunity for hearing to ERCOT and a Disclosing Party, to the extent that the Disclosing Party is known by the PUCT, the PUCT may reclassify Protected Information as non-confidential in accordance with applicable PUCT rules.

1.3.9 Expansion of Protected Information Status

A Market Participant may petition the PUCT to include specific information not listed in Section 1.3.1.1, Items Considered Protected Information, within the definition of Protected Information for good cause. In addition, a Market Participant may petition the PUCT to expand the time period for maintaining Protected Information status of specific information, or prohibit disclosure altogether, for good cause. After reasonable notice and opportunity for hearing, the PUCT may grant or deny such petition.

1.4 Operational Audit

1.4.1 Materials Subject to Audit

ERCOT's records and documentation pertaining to its operation as the certified Independent Organization for the ERCOT Region are subject to audit in the manner prescribed herein. The rights of Market Participants to audit ERCOT are limited to the provisions in Section 1.4, Operational Audit.

1.4.2 ERCOT Finance and Audit Committee

The ERCOT Board shall have overall audit responsibility for ERCOT. The ERCOT Board may fulfill audit responsibilities itself or delegate them to the ERCOT Finance and Audit ("F&A") Committee. The ERCOT F&A Committee shall appoint an external independent certified public accounting firm or firms ("Appointed Firm") to conduct certain audits. The F&A Committee may also direct the ERCOT Internal Audit Department to conduct certain audits. For audits to be performed by an Appointed Firm, the F&A Committee shall make recommendations to the ERCOT Board in relation to the approval, initiation, and scheduling of such audits. The ERCOT F&A Committee shall approve an annual audit plan for the ERCOT Internal Audit Department.

1.4.3 Operations Audit

1.4.3.1 Audits to Be Performed

(1) At least annually, an Appointed Firm shall review ERCOT management's compliance with its market operations policies and procedures. The scope of the audit(s) shall include examination of the processing of ERCOT's receipts and disbursements as the agent on behalf of Market Participants in compliance with these Protocols and any audit required by the PUCT. ERCOT may incorporate the scope of this audit into its annual Statement on Auditing Standards (SAS) No. 70 ("SAS 70"), Type II report.

(2) The ERCOT Internal Audit Department will conduct an annual audit of the following:

(a) Compliance with ERCOT's policies that prohibit employees from:

(i) being involved in business decisions where the individual stands to gain or lose personally from the decision;

(ii) having a direct financial interest in a Market Participant;

(iii) serving in an advisory, consulting, technical or management capacity for any business organization that does significant business with ERCOT (other than through service on ERCOT committees); and

(iv) accepting any gifts or entertainment of significant value from employees or representatives of any Market Participant doing business in ERCOT. Such gifts and entertainment shall not exceed the limits specified in ERCOT's Code of Conduct and Ethics Corporate Standard and other applicable policies.

(b) Whether ERCOT is operating in compliance with the confidentiality and Protected Information provisions of these Protocols;

(c) Verification that ERCOT, in its administration of these Protocols, is operating independently of control by any Market Participant or group of Market Participants; and

(d) Any audit required by the PUCT.

1.4.3.2 Material Issues

(1) The audits performed under Section 1.4.3.1, Audits to be Performed, may also include material issues raised by ERCOT Members and/or Market Participants if:

(a) Such issues have been presented to TAC, approved by TAC and approved by the ERCOT F&A Committee for inclusion in the audit scope; or

(b) Such issues are part of a random sample of complaints selected by the auditors for review, and affected Market Participants have agreed in writing to the examination of their related information in the compliance audit.

(2) Members and Market Participants shall send any requests regarding such issues to the ERCOT TAC Chairperson designee identified on the MIS for inclusion on the TAC agenda.

1.4.4 Audit Results

Unless a longer time frame is reasonably necessary (e.g., for the market settlements audit [SAS 70, Type II Audit], which is performed over a significant period of time), each audit report will be prepared and finalized no later than four months after the initiation of the audit. Results of all audits performed pursuant to this Section shall be reported to the F&A Committee. These audits will be filed with the PUCT in accordance with PUCT Rules. ERCOT may file an audit as confidential and Protected Information in order to protect Protected Information and other confidential or sensitive information therein. Findings and recommended actions identified as a result of an audit will be reviewed by the F&A Committee. The results of the audits required by this Section recommended actions to be taken by ERCOT shall be provided to ERCOT Members and Market Participants upon request to the extent these items do not contain Protected Information or other confidential or sensitive information.

1.4.5 Availability of Records

Subject to the requirements of Section 1.4.6, Confidentiality of Information, ERCOT will provide the ERCOT Internal Audit Department, and/or the Appointed Firm and any other staff augmentation resources full and complete access to all financial books, cost statements, accounting records, and all documentation pertaining to the requirements of the specific audits being performed. ERCOT will retain records relating to audits until the records retention requirements of ERCOT are satisfied; or until the audit issues are fully resolved, whichever is the later. Such retention shall be a term of not less than four years and not be required for more than seven years. This Section 1.4, Operational Audit, is not intended to require ERCOT to create any new records, reports, studies, or evaluations.

1.4.6 Confidentiality of Information

All Protected Information as defined in these Protocols obtained by the Appointed Firm or other staff augmentation resources through any audits will remain strictly confidential. To retain control of Protected Information, ERCOT will require that each Appointed Firm and each individual staff augmentation resource either (i) sign a confidentiality agreement with terms substantially similar to the terms of Section 1.3, Confidentiality, above before being allowed access to any ERCOT records or documentation; or (ii) observe the Appointed Firm's internal confidentiality policies and procedures, whichever is acceptable to ERCOT's Legal Department but is no less stringent than the terms of Section 1.3. Audit reports and/or results provided to Market Participants or ERCOT Members shall not contain any Protected Information.

1.5 ERCOT Fees and Charges

Fees and charges to Market Participants for use of the ERCOT scheduling, settlement, registration, and other related systems and equipment are set forth in these Protocols. The ERCOT Board may adopt additional fees and charges as reasonably necessary to cover the additional costs of such systems and equipment. Market Participants are responsible for all such applicable fees and charges. ERCOT shall post a schedule of ERCOT fees and charges on the MIS Public Area within two Business Days of change.

1.6 Open Access to the ERCOT Transmission Grid

1.6.1 Overview

Open access to the ERCOT Transmission Grid must be provided to all Eligible Transmission Service Customers by Transmission Service Providers (TSPs) and ERCOT under these Protocols and the P.U.C. Substantive Rules, Chapter 25, Substantive Rules Applicable to Electric Service Providers, Subchapter I, Transmission and Distribution.

1.6.2 Eligibility for Transmission Service

Transmission Service is available to all Eligible Transmission Service Customers. Energy may be transmitted and Ancillary Service may be provided on behalf of an Eligible Transmission Service Customer through the ERCOT System only through a QSE.

1.6.3 Nature of Transmission Service

Transmission Service allows all Eligible Transmission Service Customers to deliver and receive Energy using the Transmission Facilities of all of the Transmission Service Providers in ERCOT under P.U.C. Substantive Rules.

1.6.4. Payment for Transmission Access Service

ERCOT may not collect Transmission Access Service fees for the TSPs' cost of service. ERCOT shall provide volumetric data, pursuant to Section 9, Settlement and Billing, to the TSPs so that the TSPs can calculate their Transmission access fees. ERCOT's collection and settlement process associated with ERCOT's scheduling and deployment of Ancillary Service is addressed separately in these Protocols.

1.6.5 Interconnection of New Generation

Interconnection of new All-Inclusive Generation Resources to the ERCOT Transmission Grid must be in accordance with the ERCOT Standard Generation Interconnection Agreement (SGIA) and associated procedures.

1.7 Rules of Construction

(1) Capitalized terms and acronyms used in the Protocols have the meanings set out in Section 2, Definitions and Acronyms, of these Protocols or the meanings expressly set out in another Section of the Protocols. If a capitalized term or acronym is defined in both Section 2, and another Section of these Protocols, then the definition in that other Section controls the meaning of that term or acronym in that Section, but the definition in Section 2, controls in all other Sections of the Protocols; and

(2) In these Protocols, unless the context clearly otherwise requires:

(a) The singular includes the plural and vice versa;

(b) The present tense includes the future tense, and the future tense includes the present tense;

(c) Words importing any gender include the other gender;

(d) The words “including,” “includes,” and “include” are deemed to be followed by the words “without limitation;”

(e) The word “shall” denotes a duty;

(f) The word “will” denotes a duty, unless the context denotes otherwise;

(g) The word “must” denotes a condition precedent or subsequent;

(h) The word “may” denotes a privilege or discretionary power;

(i) The phrase “may not” denotes a prohibition;

(j) Reference to a Section, Attachment, Exhibit, or Protocol means a Section, Attachment, Exhibit, or provision of these Protocols;

(k) References to any statutes, regulations, tariffs, or these Protocols are deemed references to such statute, regulation, tariff, or Protocol as it may be amended, replaced, or restated from time to time;

(l) Unless expressly stated otherwise, references to agreements and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent that the amendments and other modifications are not prohibited by these Protocols;

(m) References to persons or Entities include their respective successors and permitted assigns and, for governmental Entities, Entities succeeding to their respective functions and capacities;

(n) References to “writing” include printing, typing, lithography, and other means of reproducing words in a tangible visible form;

(o) Any reference to a day, week, month, or year is to a calendar day, week, month, or year unless otherwise noted; and

(p) Any reference to time is to Central Prevailing Time; the 24-hour clock is used unless otherwise noted.

(q) Any reference to dollars is U.S. currency dollars unless otherwise noted.

(r) All Settlement calculations are in dollars (USD), unless otherwise noted.

(s) Any reference to energy is electrical energy, unless otherwise noted.

(3) These provisions apply to giving notice under the Protocols:

(a) Whenever these Protocols require an Entity to send a notice to another Entity and do not specify the method by which that notice should be sent, then the notice may be sent by:

(i) Hand-delivery:

(ii) Electronic mail;

(iii) Facsimile transmission;

(iv) Overnight delivery service (e.g., Federal Express, DHL or similar service) that requires a signed receipt;

(v) The Messaging System or other electronic means provided for by these Protocols; or

(vi) U.S. Mail, first class postage prepaid, registered (or certified) mail, return receipt requested, properly addressed.

(b) Notice by facsimile, electronic mail, the Messaging System, or other electronic means provided for by these Protocols is considered received when sent unless transmitted after 5:00 p.m. local time of the recipient or on a non-Business Day, in which case it is considered received one Business Day after it was sent.

(c) Notice by overnight delivery service that requires a signed receipt is considered received on the day that it was received.

(d) Notice by U.S. Mail is considered received three days after the date it was deposited in the U.S. Mail, first class postage prepaid, registered (or certified) mail, return receipt requested, properly addressed.

(e) For any notice sent by facsimile or electronic mail, the sender must promptly confirm the notice, in writing, by delivering the notice by:

(i) U.S. Mail, first class postage prepaid, registered (or certified) mail, return receipt requested, properly addressed;

(ii) Overnight delivery service requiring a signed receipt; or

(iii) Hand-delivery.

(f) If the Protocols require notice to a registered Market Participant by ERCOT, ERCOT must send the notice to the then-current Authorized Representative, if any, for the Market Participant as set forth in the Market Participant's Application for Registration on file with ERCOT or another representative designated in writing by the Authorized Representative for the purpose of receiving communications from ERCOT.

(g) When the Protocols require a notice to be in writing, sending it by electronic mail, the Messaging System, or other electronic means satisfies the requirement that the notice be in writing.

(4) Nothing in these Protocols may be construed to grant any jurisdiction or authority to NERC or FERC that they do not otherwise have.

1.8 Effective Date

Provisions of these Protocols approved through the process set forth in Section 21, Process for Protocol Revision, but not implemented until a specified later date or in accordance with other specified prerequisites to implementation, must be set forth, and the approved but not yet implemented provision must be set forth in boxes within the Protocols.

ERCOT Nodal Protocols

Section 2: Definitions and Acronyms

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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2 DEFINITIONS AND ACRONYMS

The list of acronyms is at the end of this Definitions Section.

2.1 DEFINITIONS

Definitions are supplied for terms used in more than one Section of the Protocols. If a term is used in only one Section, it is defined there at its earliest usage.

A

Adjusted Metered Load (AML)

Retail Load usage data that has been adjusted for Unaccounted for Energy (UFE), Transmission Losses, Distribution Losses, and DC Tie exports (except for the Oklaunion Exemption).

Adjustment Period

For each Operating Hour, the time between 1800 in the Day-Ahead up to the start of the hour before that Operating Hour.

Advisory

The second of four possible levels of communication issued by ERCOT in anticipation of a possible Emergency Condition, detailed in Section 6.5.9, Emergency Operations.

Affiliate

(a) An Entity that directly or indirectly owns or holds at least five percent of the voting securities of another Entity; or

(b) An Entity in a chain of successive ownership of at least five percent of the voting securities of another Entity; or

(c) An Entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by another Entity; or

(d) An Entity that has at least five percent of its voting securities owned or controlled, directly or indirectly, by an Entity who directly or indirectly owns or controls at least five percent of the voting securities of another Entity or an Entity in a chain of successive ownership of at least five percent of the voting securities of another Entity; or

(e) A person who is an officer or director of another entity or of a corporation in a chain of successive ownership of at least five percent of the voting securities of an Entity; or

(f) Any other Entity determined by the PUCT to be an Affiliate.

Agreement

A signed written agreement between ERCOT and a Market Participant using one of the standard form agreements in Section 22 of these Protocols, including those agreements containing changes to the standard form, which changes have been approved by the ERCOT Board.

Alert

The third of four possible levels of communication issued by ERCOT in anticipation of a possible Emergency Condition, detailed in Section 6.5.9, Emergency Operations.

All-Inclusive Generation Resource *(see* Resource*)*

All-Inclusive Resource *(see* Resource*)*

Alternative Dispute Resolution (ADR)

Procedures, outlined in Section 20, Alternative Dispute Resolution Procedure, for settling disputes by means other than litigation.

Ancillary Service

A service necessary to support the transmission of energy to Loads while maintaining reliable operation of the Transmission Service Provider's transmission system using Good Utility Practice.

Ancillary Service Capacity Monitor

A set of processes described in Section 8.1.2.3, QSE Ancillary Service Capacity Compliance Monitoring Criteria, to determine the real-time capability of Resources to provide Ancillary Service.

Ancillary Service Obligation

For each Ancillary Service, a QSE's ERCOT-allocated share of total ERCOT System needs for that Ancillary Service.

Ancillary Service Offer

An offer to supply Ancillary Service capacity in the Day-Ahead Market or a Supplemental Ancillary Service Market.

Ancillary Service Resource Responsibility

The MW of an Ancillary Service that each Resource is obligated to provide in Real-Time rounded to the nearest MW.

Ancillary Service Schedule

The MW of each Ancillary Service that each Resource is providing in Real-Time and the MW of each Ancillary Service for each Resource for each hour in the Current Operating Plan.

Ancillary Service Plan

A plan produced by ERCOT, as described in Section 4.2.1, Ancillary Service Plan and Ancillary Service Obligation, which identifies the types and amount of Ancillary Service necessary for each hour of the Operating Day.

Ancillary Service Supply Responsibility

The net amount of Ancillary Service capacity that a QSE is obligated to deliver to ERCOT, by hour and service type, from Resources represented by the QSE.

Ancillary Service Trade

A QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

Applicable Legal Authority (ALA)

A Texas or federal law, rule, regulation, or applicable ruling of the Commission or any other regulatory authority having jurisdiction, an order of a court of competent jurisdiction, or a rule, regulation, applicable ruling, procedure, Protocol, guide or guideline of the Independent Organization, or any Entity authorized by the Independent Organization to perform registration or settlement functions.

Area Control Error (ACE)

A calculation of the MW correction needed to control the actual system frequency to the scheduled system frequency.

Authorized Representative

The person designated by an Entity through the registration process under Section 16, Registration and Qualification of Market Participants, who is responsible for administrative communications between ERCOT and the Entity the person represents, and who has enough authority to commit and bind the Entity the person represents.

Automatic Voltage Regulator

A device on a Generation Resource used to automatically control the Generation Resource's voltage to an established set point.

Availability Plan

An hourly representation of availability of Reliability Must-Run (RMR) Units, Synchronous Condenser Units, or Black Start Resources submitted to ERCOT by 0600 in the Day Ahead by QSEs representing RMR Units or Black Start Resources.

B

Bank Business Day *(see* Business Day*)*

Bankrupt

The condition of an Entity that:

(a) Files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;

(b) Makes an assignment or any general arrangement for the benefit of creditors;

(c) Has a liquidator, administrator, receiver, trustee, conservator, or similar official appointed with respect to it or any substantial portion of its property or assets; or

(d) Is generally unable to pay its debts as they fall due.

Base Point

The MW output level for a Resource produced by the SCED process.

Black Start Resource

A Generation Resource under contract with ERCOT to provide Black Start Service.

Black Start Service

An Ancillary Service provided by a Resource able to start without support of the ERCOT Transmission Grid.

Block Load Transfer (BLT)

A transfer system that isolates a group of Loads from the Control Area in which they normally are served and then connects them to an adjacent Control Area. Such transfer systems involve either transferring Loads normally in ERCOT to a Non-ERCOT Control Area or transferring Loads normally in Non-ERCOT Control Areas to the ERCOT Control Area.

Bus Load Forecast

A set of processes used by ERCOT to determine a forecast of the Load at each Electrical Bus in the ERCOT Transmission Grid.

Business Day

Monday through Friday, excluding observed holidays listed below:

(a) New Year's Day;

(b) Memorial Day;

(c) Independence Day;

(d) Labor Day;

(e) Thanksgiving Thursday and Friday; and

(f) Two days at Christmas, as designated from time to time by the ERCOT CEO.

Bank Business Day

Any day during which the United States Federal Reserve Bank of New York is open for normal business activity.

Retail Business Day

Same as a Business Day, except in the case of retail transactions processed by a TSP or DSP, CRs shall substitute the TSP or DSP holidays for ERCOT holidays when determining the time available to the TSP or DSP to process the transaction. For additional important information related to Retail Business Days, please refer to the Retail Market Guide.

Business Hours

8:00 A.M. to 5:00 P.M. Central Prevailing Time on Business Days.

C

Capacity Trade

A QSE-to-QSE financial transaction that transfers responsibility to supply capacity between a buyer and a seller at a Settlement Point.

Central Prevailing Time (CPT)

Either Central Standard Time or Central Daylight Time, in effect in Austin, Texas.

Combined-Cycle Configuration

Any combination in which a combined-cycle power block can be operated as a separate Resource. Each possible configuration operated as a separate Resource has a distinct set of operating parameters, physical constraints, and Energy Offer Curve.

Comision Federal de Electricidad (CFE)

The state-owned federal commission of electricity of Mexico. The government agency in Mexico charged with the responsibility of operating the Mexican national electricity grid (outside Mexico City).

Common Information Model (CIM)

A standard way to communicate information about a transmission system. CIM is used to describe the ERCOT transmission system topology consisting of Transmission Elements, including all the parameters needed to describe the Transmission Elements and how they interrelate to one another. The CIM that ERCOT and the TSP use must conform to NERC and EPRI standards for CIM.

Competitive Constraint

A contingency and limiting Transmission Element pair that is determined to be competitive by an appropriate TAC Subcommittee.

Competitive Retailer (CR)

Municipally Owned Utility or an Electric Cooperative that offers Customer Choice and sells electric energy at retail in the restructured electric power market in Texas; or a Retail Electric Provider (REP) as defined in P.U.C. SUBST. R. 25.5, Definitions.

Compliance Period

A calendar year beginning January 1 and ending December 31 of each year in which Renewable Energy Credits (RECs) are required of a Retail Entity.

Compliance Premium

Awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy source that is not powered by wind and meets the criteria of subsection (l) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. For the purpose of the Renewable Portfolio Standard (RPS) requirements, one Compliance Premium is equal to one REC.

Congestion Revenue Right (CRR)

A financial instrument that entitles the holder to be charged or to receive compensation (*i.e.*, congestion rent), depending on the instrument, when the ERCOT Transmission Grid is congested in the Day-Ahead Market or in Real Time.

Flowgate Right (FGR)

A Flowgate Right is a type of CRR that entitles the holder to receive compensation and is evaluated in each CRR Auction and DAM as the positive power flows represented by the quantity of the CRR bid or offer (MW) on a flowgate (i.e., predefined directional network element or a predefined bundle of directional network elements).

Point-to-Point (PTP) Obligation

A PTP Obligation is a type of CRR that entitles the holder to be charged or to receive compensation and is evaluated in each CRR Auction and DAM as the positive and negative power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points of the quantity represented by the CRR bid or offer (MW).

Point-to-Point (PTP) Option

A PTP Option is a type of CRR that is evaluated in each CRR Auction and DAM as the positive power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points in the quantity represented by the CRR bid or offer (MW), excluding all negative flows on all directional network elements. A PTP Option entitles the holder to receive compensation equal to the positive energy price difference between the sink and the source settlement point prices. A PTP Option with Refund is evaluated in the same manner and compensated as described in Section 7.4.2, PCRR Allocation Terms and Conditions.

Continuous Service Agreement (CSA)

An arrangement between the owner or controller of a leased Premise and a Competitive Retailer (CR) wherein the CR provides service to the leased Premise between tenants so that the Premise does not experience discontinuation of electric service during vacancy.

Controllable Load Resource Desired Load

The MW consumption for a Controllable Load Resource produced by summing its Scheduled Power Consumption and Ancillary Services deployments.

Controllable Load Resource (*see* Resource)

Control Area

An electrical system, bound by interconnect (tie line) metering and telemetry, that continuously regulates, through automatic Resource control, its Resource(s) and interchange schedules to match its system Load and frequency schedule.

Control Area Operator (CAO)

An individual or set of individuals responsible for monitoring and controlling operation of a Control Area.

Cost Allocation Zone

One of the four zones in effect during the 2003 ERCOT market as they are changed pursuant to Section 3.4.2, Load Zone Modifications. A Cost Allocation Zone may be used by ERCOT to uplift certain costs to a QSE's Load regardless of NOIE Load Zone.

Counter-Party

A single Entity that is a QSE and/or a CRR Account Holder. A Counter-Party includes all registrations as a QSE, all Subordinate QSEs, and all CRR Account Holders by the same Entity.

CR of Record

The Competitive Retailer assigned to the ESI ID in ERCOT's database. There can be no more than one CR of Record assigned to an ESI ID for any given time period.

Critical Energy Infrastructure Information (CEII)

Information concerning proposed or existing critical infrastructure (physical or virtual) that:

(a) Relates to the production, generation, transmission or distribution of energy;

(b) Could be useful to a person planning an attack on critical infrastructure;

(c) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. §522; and

(d) Gives strategic information beyond the location of the critical infrastructure.

CRR Account Holder

An Entity that is qualified to become the owner of record of CRRs and is registered as a CRR Account Holder with ERCOT

CRR Auction

A periodic auction by ERCOT that allows eligible CRR Account Holders to buy and sell CRRs.

CRR Network Model

A model of ERCOT network topology to be used in conducting a CRR Auction. It must be based on, but is not the same as, the Updated Network Model, as detailed in Section 3.10.3, CRR Network Model.

CRR Owner

The CRR Account Holder that owns one or more CRRs.

Current Operating Plan (COP)

A plan by a QSE reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service Schedule.

COP and Trades Snapshot

A record of a QSE's Capacity Trades, Energy Trades, and most recent COP.

Customer

An Entity that purchases electricity for its consumption.

Customer Choice

The freedom of a retail Customer to purchase electric services, either individually or on an aggregated basis with other retail Customers, from the provider or providers of the Customer's choice and to choose among various fuel types, energy efficiency programs, and renewable power suppliers.

Customer Registration Database

The database maintained by the registration agent containing information identifying each Premise, including current and previous Competitive Retailers serving the Premise.

D

DAM-Committed Interval

A Settlement Interval for which the Resource has been committed due to a Day-Ahead Market award.

DAM Energy Bid

A proposal to buy energy in the Day-Ahead Market at a Settlement Point at a monotonically decreasing price with increasing quantity.

Data Aggregation

The process of netting, grouping, and summing Load consumption data, applying appropriate profiles, Transmission Loss Factors, and Distribution Loss Factors and calculating and allocating UFE to determine each QSE and/or Load Serving Entity's responsibility by Settlement Interval by Load Zone and by other prescribed aggregation determinants.

Data Aggregation System (DAS)

The database and communication system that collects meter data from TSPs, DSPs and ERCOT Polled Settlement Meters. The system performs aggregation functions to the Load data in order to satisfy certain objectives, such as providing TSPs with Load share data to use in billing Competitive Retailers, assigning QSE Load responsibility, and assisting Competitive Retailers and QSEs in their settlement responsibilities. The data is also compiled along Load and Weather Zones.

Data Archive

An integrated normalized data structure of all the target source systems' transactions. The population of the data archive is an extraction of data from the transaction systems without altering the data. The Data Archive is used to populate the Data Warehouse.

Data Warehouse

De-normalized data stored in a schema, physically optimized to handle high volumes of data and concurrent user access, and generally lightly indexed.

Day-Ahead

The 24-hour period before the start of the Operating Day.

Day-Ahead Market (DAM)

A daily, co-optimized market in the Day-Ahead for Ancillary Service capacity, certain Congestion Revenue Rights, and forward financial energy transactions.

Day-Ahead Operations

The Day-Ahead process consisting of the Day-Ahead Market (DAM), and Day-Ahead Reliability Unit Commitment (DRUC).

Day-Ahead Reliability Unit Commitment (DRUC)

A Reliability Unit Commitment process performed for the next Operating Day.

DC Tie Load

A Load used to represent the withdrawal of power from the ERCOT System to a DC Tie.

DC Tie Resource

A Resource used to represent the injection of power into the ERCOT System from a DC Tie.

DC Tie Schedule

The information for a physical transaction between a buyer and a seller, one of which is in ERCOT and the other of which is in a Non-ERCOT Control Area, for energy at a Settlement Point that is a DC Tie.

Delivery Plan

A plan by ERCOT containing the hours and levels of operation that a Reliability Must-Run Unit, including a synchronous condenser unit, is instructed to operate.

Demand

The amount of instantaneous electric power in MW delivered at any specified point or points on a system.

Designated Representative

A responsible natural person authorized by the owners or operators of a renewable Resource to register that Resource with ERCOT.

Direct Current Tie (DC Tie)

Any non-synchronous transmission interconnections between ERCOT and non-ERCOT electric power systems.

Direct Load Control (DLC)

Controlling end-use equipment (*e.g.*, air conditioning equipment, water heaters) to reduce or increase energy consumption during select periods.

Dispatch

The act of issuing Dispatch Instructions.

Dispatch Instruction

A specific command issued by ERCOT to a QSE, TSP or DSP in the operation of the ERCOT System.

Dispute Contact

Individual associated with Market Participant who is primary contact with ERCOT regarding pursuit of Alternative Dispute Resolution (ADR) request

Distribution Loss Factor (DLF)

The ratio of a Distribution Service Provider's estimated Distribution Losses to the total amount of energy deemed consumed (Interval Data Recorder plus profiled consumption) on the Distribution Service Provider's system.

Distribution Losses

The difference between the energy delivered to the Distribution System and the energy consumed by Customers connected to the Distribution System.

Distribution Service Provider (DSP)

An Entity that owns or operates a Distribution System for the delivery of energy from the ERCOT Transmission Grid to Customers.

Distribution System

That portion of an electric delivery system operating under 60 kilovolts (kV) that provides electric service to Customers or Wholesale Customers.

DSR Loads

A Load that a QSE designates to be followed by a Dynamically Scheduled Resource.

DUNS Number

A unique nine-digit common company identifier used in electronic commerce transactions, supplied by the Data Universal Numbering System (DUNS).

Dynamic Rating

The current-carrying capability of a Transmission Element adjusted to take into account the effect of ambient weather conditions.

Dynamic Rating Processor

A process used to establish ERCOT Transmission Element limits based upon factors such as ambient temperature and wind speed.

Dynamically Scheduled Resource (DSR)

A Resource that has been designated by the QSE, and approved by ERCOT, as a DSR status-type and follows a DSR Load.

E

Electric Cooperative (EC)

(a) A corporation organized under Chapter 161 of the Electric Cooperative Corporation Act, TEX. UTIL. CODE ANN. (1997);

(b) A corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct business in Texas; or

(c) A successor to an electric cooperative created before June 1, 1999, under a conversion plan approved by a vote of the members of the electric cooperative, regardless of whether the successor later purchases, acquires, merges with, or consolidates with other electric cooperatives.

Electric Reliability Council of Texas, Inc. (ERCOT)

A Texas nonprofit corporation that has been certified by the PUCT as the Independent Organization, as defined in the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §39.151 (Vernon 1998 & Supp. 2005)(PURA), for the ERCOT Region.

Electric Service Identifier (ESI ID)

The basic identifier assigned to each Service Delivery Point used in the registration and settlement systems managed by ERCOT or another Independent Organization.

Electrical Bus

(1) A physical transmission element defined in the Network Operations Model that connects, using breakers and switches, one or more:

(a) Loads,

(b) Lines,

(c) Transformers,

(d) Generators,

(e) Capacitors,

(f) Reactors,

(g) Phase shifters, and

(h) Other reactive control devices to the ERCOT Transmission Grid where there is negligible impedance between the connected Transmission Elements.

(2) All Electrical Buses are designated by ERCOT and TSPs for modeling the electrical topology of the ERCOT Transmission Grid.

Eligible Transmission Service Customer

A Transmission and/or Distribution Service Provider (for all uses of its transmission system), or any electric utility, Municipally Owned Utility, Electric Cooperative, power generation company, Competitive Retailer, Retail Electric Provider, federal power marketing agency, exempt wholesale generator, Qualifying Facility, power marketer, or other Entity that the PUCT has determined to be an Eligible Transmission Service Customer.

Emergency Base Point

The target MW output level for a Resource that is selected by ERCOT during an Emergency Condition.

Emergency Condition

Either:

(1) An operating condition in which the safety or reliability of the ERCOT System is compromised or threatened, as determined by ERCOT; or

(2) The failure of the SCED process.

Emergency Electric Curtailment Plan (EECP)

A plan that provides an orderly, predetermined procedure for maximizing use of available Resources and, only if necessary, curtailing load during an Emergency Condition while providing for the maximum possible continuity of service and maintaining the integrity of the ERCOT System.

Emergency Interruptible Load Service (EILS)

A special emergency service consistent with subsection (a) of PUC SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Interruptible Load Service (EILS), used during an EECP to reduce Load and assist in maintaining or restoring ERCOT System frequency. EILS is not an Ancillary Service.

EILS Contract Period

A time frame during which ERCOT may procure EILS in an amount no greater than 1000 MW.

EILS Load

A Load or aggregation of Loads that is contracted to provide EILS.

EILS Self-Provision

The act by a QSE to meet its Load Ratio Share (LRS) of the total EILS procurement by designating Load to act as an EILS Load. A QSE self-providing EILS shall submit EILS offers at a price of zero dollars.

EILS Time Period

Blocks of hours in an EILS Contract Period in which EILS Loads are contractually committed to provide EILS. EILS Time Periods are specific to an EILS Contract Period and shall be defined by ERCOT in the Request for Proposal for that EILS Contract Period.

Emergency Ramp Rate

The maximum rate of change in MW per minute of a Resource to provide Responsive Reserve that is deployed by ERCOT and that is provided to ERCOT in up to ten segments, each represented by a single MW per minute value (across the capacity of the Resource), which describes the available rate of change in output for the given range (between HSL and LSL) of the output of a Resource.

Emergency Rating *(see* Ratings*)*

Energy Imbalance Service

An Ancillary Service that is provided when a difference occurs between the scheduled and the actual delivery of energy in Real-Time.

Energy Offer Curve

A proposal to sell energy at a Settlement Point at a monotonically increasing price with increasing quantity.

Energy Trade

A QSE-to-QSE financial transaction that transfers responsibility for energy between a buyer and a seller at a Settlement Point.

Entity

Any natural person, partnership, municipal corporation, cooperative corporation, association, governmental subdivision, or public or private organization.

ERCOT Board

The Board of Directors of the Electric Reliability Council of Texas, Inc.

ERCOT CEO

The Chief Executive Officer of ERCOT.

ERCOT Member

Any member of ERCOT in good standing under the ERCOT Bylaws.

ERCOT Operator

An employee of ERCOT responsible for operating the ERCOT Transmission Grid

ERCOT-Polled Settlement (EPS) Meter

Any meter polled directly by ERCOT for use in the financial settlement of the market.

ERCOT Region

The power region represented by the ERCOT Control Area.

ERCOT System

The interconnected power system that is under the jurisdiction of the PUCT and that is not synchronously interconnected with either the Eastern Interconnection or the Western Electricity Coordinating Council.

ERCOT System Demand

The sum of all power flows, in MW, on the DC Ties and from Generation Resources metered at the point of its interconnection with the ERCOT System at any given time.

ERCOT Transmission Grid

All Transmission Facilities that are part of the ERCOT System.

F

Facility Identification Number

A number assigned to a renewable Resource facility by ERCOT.

15-Minute Rating *(see* Ratings*)*

Financing Persons

The lenders, security holders, investors, partners, multilateral institutions, and other Entities providing financing or refinancing for the business of another Entity, including development, construction, ownership, operation and/or maintenance of a facility or any portion thereof, or any trustee or agent acting on behalf of any of the foregoing.

Flowgate Right (FGR) (*see* Congestion Revenue Right (CRR))

Force Majeure Event

Any event beyond the reasonable control of, and that occurs without the fault or negligence of, an Entity whose performance is prevented by the occurrence of such event. Examples of such a Force Majeure Event may include the following, subject to the limitations of the above sentence: an act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or a curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities.

Forced Outage (*see* Outage)

Fuel Index Price (FIP)

The midpoint price expressed in dollars per million British thermal units ($/MMBtu), published in *Gas Daily*, in the Daily Price Survey, under the heading "East-Houston-Katy, Houston Ship Channel." The *Gas Daily* indicates which flow dates the prices are effective. For Saturdays, Sundays, holidays, and other days for which *Gas Daily* does not publish an effective price, the effective price shall be the effective price for the Operating Day following the holiday or day without a published price. If, at the time of calculation of peaking operating cost of System-Wide Offer Cap, or at the time of settlement or calculation of generic costs, the described midpoint price for a particular Operating Day is not available, the effective price for the most recent preceding Operating Day shall be used.

Fuel Oil Price (FOP)

The sum of five cents per gallon plus the average of the *Platts Oilgram Price Report* for U.S. Gulf Coast, pipeline No. 2 oil, converted to dollars per million British thermal units ($/MMBtu). The conversion is 0.1385 MMBtu per gallon. The *Platts Oilgram Price Report* indicates which Operating Days the prices are effective. In the event, at the time of settlement or calculation of generic costs, that the effective price for a particular Operating Day is not available, the effective price for the most recent preceding Operating Day shall be used.

G

Generation Entity

Owner of an All-Inclusive Generation Resource.

Generation Resource *(see* Resource*)*

Generic Transmission Limit (GTL)

A transmission flow limit more constraining than a Transmission Element's Normal Limit established to constrain flow between geographic areas of the ERCOT Transmission System that is used to enforce stability and voltage constraints that can not be modeled directly in ERCOT's transmission security analysis applications.

Good Utility Practice

Any of the practices, methods, and acts engaged in, or approved by, a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

Governmental Authority

Any federal, state, local, or municipal body having jurisdiction over a Market Participant or ERCOT. But a Governmental Authority that is also a Market Participant may not exercise its jurisdiction in any matter that involves the interests of that Market Participant where that matter also involves the interests or responsibilities of any other Market Participant or ERCOT, unless the matter is one in which the Market Participant has exclusive jurisdiction.

H

High Ancillary Service Limit (HASL)

A dynamically calculated MW upper limit on a Resource to reserve the part of the Resource's capacity committed for Ancillary Service, calculated as described in Section 6.5.7.2, Resource Limit Calculator.

High Emergency Limit (HEL)

Limit established by the QSE describing the maximum temporary unsustainable energy production capability of the Resource. This limit must be achievable for a time stated by the QSE, but not less than 30 minutes.

High Sustained Limit (HSL for a Generation Resource)

Limit established by the QSE, continuously updated in Real Time, that describes the maximum sustained energy production capability of the Resource.

High Sustained Limit (HSL for a Load Resource)

Limit calculated by ERCOT, using the QSE-established Low Power Consumption.

Hourly Reliability Unit Commitment (HRUC)

Any Reliability Unit Commitment executed after the Day-Ahead RUC.

Hub

A designated Settlement Point consisting of a Hub Bus or group of Hub Buses and the settlement price calculation methodology that is set out in the definition of the Hub in Section 3.5.2, Hub Definitions. Hubs may only be created by an amendment to Section 3.5.2. The list of Hub Buses and the settlement price calculation methodology that define a Hub can never be modified and a Hub, once defined, exists in perpetuity.

Hub Bus

An energized Electrical Bus or group of energized Electrical Buses defined as a single element in the Hub definition. The LMP of the Hub Bus is the simple average of the LMPs assigned to each energized Electrical Bus in the Hub Bus. If all Electrical Buses within a Hub Bus are de-energized, the LMP of the Hub does not include the de-energized Hub Bus. This is used solely for calculating the prices of existing Hub Buses defined in Section 3.5.2, Hub Definitions.

I

Independent Market Monitor (IMM)

The Entity selected to monitor the wholesale electric market pursuant to the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.1515 (Vernon 1998 & Supp. 2007) and PUC SUBST. R. 25.365, Independent Market Monitor.

Independent Organization

An independent organization as defined in the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §39.151 (Vernon 1998 & Supp. 2005)

Intermittent Renewable Resource (IRR)

Generation Resources that can only produce energy from variable, uncontrollable Resources such as wind, solar, or run-of-the-river-hydro.

Interval Data Recorder (IDR)

Metering device that is capable of recording Load in each Settlement Interval under Section 9, Settlement and Billing, and Section 10, Metering.

Invoice

A notice for payment or credit due rendered by ERCOT.

J

K

L

Level I Maintenance Outage (*see* Outage)

Level II Maintenance Outage (*see* Outage)

Level III Maintenance Outage (*see* Outage)

Load

The amount of energy in MWh delivered at any specified point or points on a system.

Load Frequency Control (LFC)

Deployment of those Generation Resources that are providing Regulation Service to ensure that system frequency is maintained within predetermined limits and deployment of those Generation Resources that are providing Responsive Reserve Service when necessary as backup regulation. LFC does not include the deployment of Responsive Reserve by Load Resources when deployed as a block under Emergency Electric Curtailment Plan (EECP) procedures.

Load Profile

A representation of the energy usage of a group of Customers, showing the Demand variation on an hourly or sub-hourly basis.

Load Profile Models

Processes that use analytical modeling techniques to create Load Profiles.

Load Profile Type

A classification of a group of Customers having similar energy usage patterns and that are assigned the same Load Profile.

Load Profiling

The set of processes used to develop and create Load Profiles.

Load Ratio Share

The ratio of an Entity's Adjusted Metered Load to total ERCOT Adjusted Metered Load for an interval.

Load Resource *(see* Resource*)*

Load Serving Entity

An Entity that sells energy to Customers or Wholesale Customers and that has registered as an LSE with ERCOT. Load Serving Entities include Competitive Retailers (which includes Retail Electric Providers) and Non-Opt-In Entities that serve Load.

Load Zone

A group of Electrical Buses assigned to the same zone under Section 3.4, Load Zones. Every Electrical Bus in ERCOT with a Load must be assigned to a Load Zone for settlement purposes. A NOIE Load Zone is a type of Load Zone.

Locational Marginal Price (LMP)

The offer-based marginal cost of serving the next increment of Load at an Electrical Bus, which marginal cost is produced by the DAM process or by the SCED process.

Low Ancillary Service Limit (LASL)

A dynamically calculated MW lower limit on a Resource to maintain the ability of the Resource to provide committed Ancillary Service.

Low Emergency Limit (LEL)

Limit established by the QSE describing the minimum temporary unsustainable energy production capability of the Resource. This limit must be achievable for a period of time indicated by the QSE but not less than 30 minutes.

Low Power Consumption (LPC for a Load Resource)

Limit established by the QSE, continuously updated in Real-Time, that describes the minimum sustained power consumption of the Load Resource.

Low Sustained Limit (LSL for a Load Resource)

Limit calculated by ERCOT, using the QSE-established Maximum Power Consumption.

Low Sustained Limit (LSL for a Generation Resource)

Limit established by the QSE, continuously updatable in Real-Time, that describes the minimum sustained energy production capability of the Resource.

M

Maintenance Outage (*see* Outage)

Make-Whole Payment

A payment made by ERCOT to the QSE for a Resource to reimburse the QSE for allowable startup and minimum energy costs of the Resource not recovered in energy revenue when the Resource is committed by the DAM or by a RUC.

Make-Whole Charge

A charge made by ERCOT to a QSE for a Resource to recapture all or part of the revenues received by the QSE that exceed the Make-Whole Payment for the Resource.

Mandatory Installation Threshold

A peak demand greater than 700 kW (or 700 kVA).

Market Clearing Price for Capacity (MCPC)

The hourly price for Ancillary Service capacity awarded in the Day-Ahead Market or a Supplemental Ancillary Service Market.

Market Information System (MIS)

An electronic communications interface established and maintained by ERCOT that provides a communications link to the public and to Market Participants, as a group or individually.

MIS Public Area

The portion of the MIS that is available to the public.

MIS Secure Area

The portion of the MIS that is available only to registered users.

MIS Certified Area

The portion of the MIS that is available only to a specific Market Participant.

Market Participant

An Entity that engages in any activity that is in whole or in part the subject of these Protocols, regardless of whether that Entity has signed an Agreement with ERCOT. Examples of such Entity are, but not limited to the following: LSE, QSE, TDSP, CRR Account Holder, Resource Entity, and REC Account Holder.

Mass Drop

The immediate cessation of service by a Competitive Retailer (CR) to all ESI IDs served by the CR.

Master QSE

The QSE that manages the meter-splitting telemetry and the verifiable cost submission for split Generation Resource meters.

Maximum Power Consumption (MPC for a Load Resource)

Limit established by the QSE, continuously updated in Real-Time, that describes the maximum sustained power consumption of the Load Resource.

Messaging System

The ERCOT-to-QSE communications system used to send Real-Time notices and Dispatch Instructions to QSEs.

Meter Data Acquisition System (MDAS)

The system to obtain revenue quality meter data from ERCOT Polled Settlement meters and Settlement Quality Meter Data from the TSPs and DSPs for settlement and to populate the Data Aggregation System and Data Archive.

Meter Reading Entity (MRE)

A TSP or DSP that is responsible for providing ERCOT with ESI ID level consumption data as defined in Section 19, Texas Standard Electronic Transaction. In the case of an ERCOT-Polled Settlement (EPS) Meter or ERCOT populated ESI ID data (such as Generation Resource site load), ERCOT will be identified as the MRE in ERCOT systems.

Minimum-Energy Offer

Represents an offer for the costs incurred by a Resource in producing energy at the Resource's LSL expressed in dollars per MWh.

Minimum Reservation Price

The lowest price that a seller is willing to accept.

Mitigated Offer Caps

An upper limit on the price of an offer as detailed in Section 4.4.9.4.1, Mitigated Offer Cap.

Mitigated Offer Floor

A lower limit on the price of an offer as detailed in Section 4.4.9.4.2, Mitigated Offer Floor.

Mothballed Generation Resource (*see* Resource)

Municipally Owned Utility (MOU)

A utility owned, operated, and controlled by a nonprofit corporation, the directors of which are appointed by one or more municipalities, or a utility owned, operated, or controlled by a municipality.

N

Net Dependable Capability

The maximum sustained capability of a Resource as demonstrated by performance testing.

Net Generation

Gross generation less station auxiliary Load or other internal unit power requirements metered at or adjusted to the point of interconnection with the ERCOT Transmission Grid at the common switchyard.

Network Operations Model

A representation of the ERCOT System providing the complete physical network definition, characteristics, ratings, and operational limits of all elements of the ERCOT Transmission Grid and other information from TSPs, Resource Entities, and QSEs.

Network Security Analysis

A processor used by ERCOT to monitor Transmission Elements in the ERCOT Transmission Grid for limit violations and to verify Electrical Bus voltage limits to be within a percentage tolerance as outlined in the Operating Guides.

Non-Competitive Constraint

Any Transmission Element that is not a Competitive Constraint.

Non-Metered Load or Group

Load that is not required to be metered by applicable distribution or transmission tariff.

Non-Opt-In Entity (NOIE)

An Electric Cooperative or Municipally Owned Utility that does not offer Customer Choice.

Non-Opt-In Entity (NOIE) Load Zone

A Load Zone established by a NOIE or a group of NOIEs using a one-time NOIE election.

Non-Spinning Reserve (Non-Spin)

An Ancillary Service that is provided through use of the part of Off-Line Generation Resources that can be synchronized and ramped to a specified output level within 30 minutes (or Load Resources that can be interrupted within 30 minutes) and that can operate (or Load Resources that can be interrupted) at a specified output level for at least one hour. Non-Spinning Reserve Service (Non-Spin) may also be provided from unloaded On-Line capacity that meets the 30-minute response requirements and that is reserved exclusively for use for this service.

Normal Ramp Rate

The rate of change in megawatts (MW) per minute of a Resource, which is specified by the QSE to ERCOT by up to ten segments; each segment represents a single MW per minute value (across the capacity of the Resource) that describe the available rate of change in output for the given range (between HSL and LSL) of output of a Resource.

Normal Rating *(see* Ratings*)*

Notice or Notification

Sending of information by an Entity to Market Participants, ERCOT, or others, as called for in these Protocols. Notice or notification may be sent by electronic mail, facsimile transmission, or U.S. mail.

O

Off-Line

The status of a Resource that is not synchronously interconnected to the ERCOT System.

Off-Peak Hours

Hours that are not On-Peak Hours.

Oklaunion Exemption

The export schedules from the Public Service Company of Oklahoma, the Oklahoma Municipal Power Authority, and the AEP Texas North Company for their share of the Oklaunion Resource over the North DC Tie are not treated as Load connected at transmission voltage, are not subject to any of the fees described in Section 4.4.4, DC Tie Schedules, and are limited to the actual net output of the Oklaunion Resource.

On-Line

The status of a Resource that is synchronously interconnected to the ERCOT System.

On-Peak Hours

Hours ending in 0700 to 2200 Central Prevailing Time from Monday through Friday excluding NERC holidays.

Operating Day

The day, including hours ending 0100 to 2400, during which energy flows.

Operating Guides

Guidelines approved by the ERCOT Board describing the reliability standards for ERCOT.

Operating Hour

A full clock hour during which energy flows.

Operating Period

A two-hour period comprised of the Operating Hour and the clock hour preceding the Operating Hour.

Opportunity Outage (see Outage)

Outage

The condition of a facility that has been removed from service to perform maintenance, construction, or repair on the facility.

Forced Outage

An Outage initiated by protective relay, or manually in response to an observation by personnel that the condition of equipment could lead to an event, or potential event, that poses a threat to people, equipment, or public safety.

Maintenance Outage

An Outage initiated manually to remove equipment from service to perform work on components that could be postponed briefly but that is required to prevent a potential Forced Outage and that cannot be postponed until the next Planned Outage. Maintenance Outages are classified as follows:

(1) **Level 1 Maintenance Outage –** Equipment that must be removed from service within 24 hours to prevent a potential Forced Outage;

(2) **Level II Maintenance Outage –** Equipment that must be removed from service within seven days to prevent a potential Forced Outage; and

(3) **Level III Maintenance Outage –** Equipment that must be removed from service within 30 days to prevent a potential Forced Outage.

Opportunity Outage

An Outage that may be accepted by ERCOT when a specific Resource is Off-Line due to an Outage.

Planned Outage

An Outage that is planned and scheduled in advance with ERCOT, other than a Maintenance Outage or Opportunity Outage.

Simple Transmission Outage

A Planned Outage or Maintenance Outage of any Transmission Element in the Network Operations Model such that when the Transmission Element is removed from its normal service, absent a Forced Outage of other Transmission Elements, the Outage does not cause a topology change in the LMP calculation and thus cannot cause any LMPs to change with or without the Transmission Element that is suffering the Outage.

Outage Scheduler

The application that TSPs or QSEs use to submit notification of Outages or requests for Outages to ERCOT for approval, acceptance, or rejection.

Output Schedule

The self-scheduled output for every five-minute interval of a Resource provided by a QSE before the execution of SCED.

P

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.

Planned Outage (*see* Outage)

Power System Stabilizer

A device that is installed on Generation Resources to maintain synchronous operation of the ERCOT System under transient conditions.

Point-to-Point (PTP) Obligation (*see* Congestion Revenue Right (CRR))

Point-to-Point (PTP) Option (*see* Congestion Revenue Right (CRR))

Premise

A Service Delivery Point or combination of Service Delivery Points that is assigned a single Electric Service Identifier (ESI ID) for settlement and registration.

Prior Agreement

Any previous agreement between an Entity, its Affiliate, or its predecessor in interest and ERCOT about performance under the ERCOT Protocols.

Private Use Network

An electric network connected to the ERCOT Transmission Grid that contains Load that is not directly metered by ERCOT (i.e., Load that is typically netted with internal generation).

Program Administrator

The Entity approved by the PUCT that is responsible for carrying out the administrative responsibilities for the Renewable Energy Credit Program as set forth in subsection (g) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

Protected Information

Information protected from disclosure as described in Section 1, Overview.

Provider of Last Resort (POLR)

The designated Competitive Retailer as defined in the P.U.C. Substantive Rules for default Customer service, and as further described in Section 15.1, Customer Switch of Competitive Retailer.

Q

QSE Clawback Interval

Any QSE-Committed Interval that is part of a contiguous block that includes at least one RUC-Committed Hour unless it is:

(a) QSE-committed before the first RUC instruction for any RUC-Committed Hour in that contiguous block; or

(b) Part of a contiguous block of a QSE-Committed Intervals, at least one of which was committed by the QSE before the RUC instruction described in paragraph (a) above.

QSE-Committed Interval

A Settlement Interval for which the QSE for a Resource has committed the Resource without a RUC instruction to commit it.

Qualified Scheduling Entity (QSE)

A Market Participant that is qualified by ERCOT in accordance with Section 16, Registration and Qualification of Market Participants, for communication with ERCOT for Resource Entities and Load Serving Entities and for settling payments and charges with ERCOT.

Qualifying Facility (QF)

A qualifying cogeneration facility or qualifying small power production facility under regulatory qualification criteria as defined in PURPA, 16 USC §796(18)(B) and §796(17)(C).

R

Ratings

Emergency Rating

Two-hour MVA rating of a Transmission Element.

15-Minute Rating

The 15-Minute MVA rating of a Transmission Element.

Normal Rating

The rating at which a Transmission Element can operate without reducing its normal life expectancy.

Reactive Power

The product of voltage and the out-of-phase component of alternating current. Reactive Power, usually measured in megavolt-ampere reactive, is produced by capacitors, overexcited generators and other capacitive devices and is absorbed by reactors, underexcited generators and other inductive devices.

Real-Time

The current instant in time.

REC Account

An account maintained by ERCOT for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs or Compliance Premiums by a program participant.

REC Account Holder

An Entity registered by ERCOT to produce, hold, or aggregate RECs or Compliance Premiums.

REC Trading Program

The Renewable Energy Credit Trading program, as described in Section 14, State of Texas Renewable Energy Credit Trading Program, and P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

Regulation Down Service (Reg-Down)

An Ancillary Service that provides capacity that can respond to signals from ERCOT within three to five seconds to respond to changes in system frequency. Such capacity is the amount available below any Base Point but above the Low Sustained Limit of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Down must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource's Maximum Power Consumption limit.

Regulation Service

Consists of either Regulation Up Service or Regulation Down Service.

Regulation Up Service (Reg-Up)

An Ancillary Service that provides capacity that can respond to signals from ERCOT within three to five seconds to respond to changes in system frequency. Such capacity is the amount available above any Base Point but below the High Sustained Limit of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Up must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Up above the Low Power Consumption limit.

Reliability Must-Run (RMR) Service

An Ancillary Service provided from a Reliability Must-Run Unit under an Agreement with ERCOT.

Reliability Must-Run (RMR) Unit

A Generation Resource operated under the terms of an Agreement with ERCOT that would not otherwise be operated except that it is necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria where market solutions do not exist.

Reliability Unit Commitment (RUC)

Process to ensure that there is adequate Resource capacity and Ancillary Service capacity committed in the proper locations to serve ERCOT forecasted Load.

Remedial Action Plan (RAP)

A set of pre-defined actions to be taken to relieve transmission security violations (normally post-contingency overloads or voltage violations) that are sufficiently dependable to assume they can be executed without loss of reliability to the interconnected network. These plans may be relied upon in allowing additional market use of the transmission system. RAPs may include controllable Load shedding by dispatcher or ERCOT action.

Renewable Energy Credit (REC)

A tradable instrument that represents all of the renewable attributes associated with one MWh of production from a certified renewable generator.

Renewable Portfolio Standard (RPS)

The amount of capacity required to meet the requirements of PURA §39.904 pursuant to subsection (h) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

Renewable Production Potential (RPP)

The maximum generation in MWh per interval from an Intermittent Renewable Resource that could be generated from all available units of that Resource. The Renewable Production Potential depends on the renewable energy that can be generated from the available units (wind, solar radiation, or run-of-river water supply), current environmental conditions and the energy conversion characteristics of each unit.

Repowered Facility

An existing facility that has been modernized or upgraded to use renewable energy technology to produce electricity consistent with P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

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.

Resource

The term is used to refer to both a Generation Resource and a Load Resource. “Resource” used by itself in these Protocols does not include a Non-Modeled Generator.

All-Inclusive Generation Resource

A term used to refer to both a Generation Resource and a Non-Modeled Generator.

All-Inclusive Resource

A term used to refer to a Generation Resource, Load Resource and a Non-Modeled Generator.

Controllable Load Resource

Load Resource capable of controllably reducing or increasing consumption under dispatch control (similar to AGC) and that immediately responds proportionally to frequency changes (similar to generator governor action).

Generation Resource

A generator that is capable of providing energy or Ancillary Service to the ERCOT System and is registered with ERCOT as a Generation Resource. “Generation Resource” used by itself in these Protocols does not include a Non-Modeled Generator.

Mothballed Generation Resource

A Generation Resource for which a Generation Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute an RMR Agreement, and for which the Generation Entity has not announced retirement of the Generation Resource.

Switchable Generation Resource

A Generation Resource that can be connected to either the ERCOT Transmission Grid or a non-ERCOT Control Area.

Wind-powered Generation Resource (WGR)

A Generation Resource that is powered by wind.

Load Resource

A load that is capable of providing Ancillary Service to the ERCOT System and is registered with ERCOT as a Load Resource.

Non-Modeled Generator

A generator that is:

(a) Capable of providing net output of energy to the ERCOT System;

(b) 10 MW or less in size; or greater than ten MW and registered with the PUCT according to P.U.C. SUBST. R. §25.109, Registration of Power Generation Companies and Self-Generators, as a self-generator; and

(c) Registered with ERCOT as a Non-Modeled Generator, which means that the generator may not participate in the Ancillary Service or energy markets, RUC, or SCED.

Resource Entity

An Entity that owns or controls an All-Inclusive Resource and is registered with ERCOT as a Resource Entity.

Resource ID (RID)

A unique identifier assigned to each Resource used in the registration and settlements systems managed by ERCOT.

Resource Node

The Electrical Bus defined in the Network Operations Model at which a Resource's measured output is settled. For a Generation Resource that is connected to the ERCOT Transmission Grid only by one or more radial transmission lines that all originate at the Generation Resource and terminate in a single substation switchyard, the Resource Node is an Electrical Bus in that substation. For all other Generation Resources, the Resource Node is the Generation Resource's side of the Electrical Bus at which the Generation Resource is connected to the ERCOT Transmission Grid

Resource Parameter

Registered Resource-specific parameters required for use in ERCOT business processes.

Resource Status

The operational state of a Resource as provided in Section 3.9, Current Operating Plan (COP).

Responsive Reserve

An Ancillary Service that provides operating reserves that is intended to:

(a) Arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using governor response and interruptible Load;

(b) After the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal;

(c) Provide energy or continued Load interruption during the implementation of the Emergency Electric Curtailment Plan (EECP); and

(d) Provide backup regulation.

Retail Business Day *(see* Business Day*)*

Retail Electric Provider (REP)

As defined in P.U.C. SUBST. R. 25.5, Definitions, an Entity that sells electric energy to retail Customers in Texas but does not own or operate generation assets and is not an MOU or EC.

Retail Entity

Municipally-Owned Utilities (MOUs), Generation and Transmission (G&T) cooperatives and distribution cooperatives that offer Customer Choice; Retail Electric Providers (REPs); and Investor-Owned Utilities (IOUs) that have not unbundled pursuant to Public Utility Regulatory Act (PURA) §39.051, Unbundling.

Revenue Quality Meter

For ERCOT-Polled Settlement Meters, a meter that complies with the Protocols and the Settlement Metering Operating Guides. For TSP or DSP metered Entities, a meter that complies with Governmental Authority-approved meter standards, or the Protocols and the Operating Guides.

RUC-Committed Hour

An Operating Hour for which a RUC has committed a Resource to be On-Line.

RUC-Committed Interval

A Settlement Interval for which there is a RUC instruction to commit a Resource.

RUC Study Period

As defined under Section 5.1, Introduction.

S

Scheduled Power Consumption

Expected Load, in MW, reported by a QSE for a Controllable Load Resource in the Operational Data Requirements.

Scheduled Power Consumption Snapshot

A snapshot, taken by ERCOT, of the Scheduled Power Consumption provided by the QSE for a Controllable Load Resource at the end of the adjustment period and used in determining the Controllable Load Resource Desired Load.

Season

Winter months are December, January, and February; Spring months are March, April, and May; Summer months are June, July, and August; Fall months are September, October, and November.

Security-Constrained Economic Dispatch (SCED)

The determination of desirable Generation Resource output levels using Energy Offer Curves while considering State Estimator output for Load at transmission-level Electrical Buses, Generation Resource limits, and transmission limits to provide the least offer-based cost dispatch of the ERCOT System.

Self-Arranged Ancillary Service Quantity

The portion of its Ancillary Service Obligation that a QSE secures for itself using Resources represented by that QSE and Ancillary Service Trades.

Self-Schedule

Information for Real-Time Settlement purposes that specifies the amount of energy supply at a specified source Settlement Point used to meet an energy obligation at a specified sink Settlement Point for the QSE submitting the Self-Schedule.

Service Address

The street address associated with an Electric Service Identifier (ESI ID) as recorded in the Registration Database. This address shall conform to United States Postal Service Publication 28.

Service Delivery Point

The specific point on the system where electricity flows from the TSP or DSP to a Customer.

Settlement

The process used to resolve financial obligations between a Market Participant and ERCOT.

Settlement Calendar

The Settlement Calendar provides information on when Settlement Statements and Invoices shall be posted, payment due dates and dispute deadlines. Additional information is provided in Section 9.1.2, Settlement Calendar.

Settlement Interval

The time period for which markets are settled.

Settlement Meter

Generation and end-use consumption meters used for allocation of ERCOT charges and wholesale and retail Settlements.

Settlement Point

A Resource Node, Load Zone, or Hub.

Settlement Point Price

A price calculated for a Settlement Point for each Settlement Interval using LMP data and the formulas detailed in Sections 4.6, DAM Settlement and 6.6, Settlement Calculations for the Real-Time Energy Operations.

Settlement Quality Meter Data

Data that has been edited, validated, and is appropriate for the ERCOT settlement agent to use for settlement and billing purposes.

Shadow Price

A price for a commodity that measures the marginal value of this commodity, that is, the rate at which system costs could be decreased or increased by slightly increasing or decreasing, respectively, the amount of the commodity being made available.

Shift Factor

A measure of the flow on a particular Transmission Element due to a unit injection of power from a particular Electrical Bus to a fixed reference Electrical Bus.

Short-Term Wind Power Forecast

An ERCOT produced hourly forecast of wind-power energy production potential for each WGR.

Simple Transmission Outage (*see* Outage)

Special Protection Systems (SPS)

A set of automatic actions to be taken to relieve transmission security violations (normally post-contingency overloads or voltage violations) that are sufficiently dependable to assume they can be executed without loss of reliability to the interconnected network.

Split Generation Resource

A Generation Resource that has been split to function as two or more independent Generation Resources in accordance with Section 10.3.2.1, Generation Meter Splitting and Section 3.10.7.2, Modeling of Resources and Transmission Loads.

Startup Cost

All costs incurred by a Generation Resource in starting up and reaching breaker close in dollars per start.

Startup Offer

Represents an offer for all costs incurred by a Generation Resource in starting up and reaching breaker close in dollars per start.

State Estimator (SE)

A computational algorithm that uses Real-Time inputs from the network's Supervisory Control and Data Acquisition (SCADA) system that measure the network's electrical parameters, including its topology, voltage, power flows, etc., to estimate electrical parameters (such as line flows and Electrical Bus voltages and loads) in the ERCOT Transmission Grid. The SE's output is a description of the network and all of the values (topology, voltage, power flow, etc.) to describe each Electrical Bus and line included in the system model.

System Operator

An Entity supervising the collective Transmission Facilities of a power region, which Entity is charged with coordination of market transactions, system-wide transmission planning, and network reliability.

System-Wide Offer Cap (SWACP)

The system-wide offer cap defined in subsection (g) of P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region.

T

TDSP Metered Entity

Any Entity that meets the requirements of Section 10.2.2, TSP and DSP Metered Entities.

Technical Advisory Committee (TAC)

A subcommittee in the ERCOT governance structure reporting to the Board of Directors as defined by the ERCOT Bylaws.

Texas Nodal Market Implementation Date

The date on which ERCOT starts operation of the Texas nodal market design in compliance with the rules and orders of the PUCT. Once this date is determined, ERCOT shall post it on the ERCOT website and maintain it on either the ERCOT website or the MIS Public Area thereafter.

Texas SET

Texas Standard Electronic Transaction procedures, set forth in Section 19, Texas Standard Electronic Transaction, used to transmit information pertaining to the Customer Registration Database. Record and data element definitions are provided in the data dictionary in Protocols Section 19.

Three-Part Supply Offer

An offer made by a QSE for a Generation Resource that it represents containing three components: a Startup Offer, a Minimum-Energy Offer, and an Energy Offer Curve.

Transmission Access Service

Use of a TSP's Transmission Facilities for which the TSP is allowed to charge through tariff rates approved by the PUCT.

Transmission and/or Distribution Service Provider (TDSP)

An Entity that is either a Transmission Service Provider or a Distribution Service Provider.

Transmission Element

A physical transmission facility that is either a Electrical Bus, line, transformer, generator, load, breaker, switch, capacitor, reactor, phase shifter, or other similar device that is part of the ERCOT Transmission Grid and defined in the ERCOT Network Operations Model.

Transmission Facilities

(1) Power lines, substations, and associated facilities, operated at 60 kV or above, including radial lines operated at or above 60 kV;

(2) Substation facilities on the high voltage side of the transformer, in a substation where power is transformed from a voltage higher than 60 kV to a voltage lower than 60 kV or is transformed from a voltage lower than 60 kV to a voltage higher than 60 kV; and

(3) The direct current interconnections between ERCOT and the Southwest Power Pool (SPP) or Comision Federal de Electricidad.

Transmission Loss Factors

The fraction of ERCOT Load (forecast or actual) that is considered to constitute the ERCOT Transmission Grid losses in the Settlement Interval, based on a linear interpolation (or extrapolation) of the calculated losses in the off-peak and on-peak seasonal ERCOT base cases.

Transmission Losses

Difference between energy put into the ERCOT Transmission Grid and energy taken out of the ERCOT Transmission Grid.

Transmission Service

Commercial use of Transmission Facilities.

Transmission Service Provider (TSP)

An Entity under the jurisdiction of the PUCT that owns or operates Transmission Facilities used for the transmission of electricity and provides Transmission Service in the ERCOT Transmission Grid.

U

Unaccounted for Energy (UFE)

The difference between total metered Load for each Settlement Interval, adjusted for applicable Distribution Losses and Transmission Losses, and total ERCOT System Net Generation.

Unit Reactive Limit

The maximum quantity of Reactive Power that a Generation Resource is capable of providing at a 0.95 power factor at its maximum real power capability.

Updated Desired Base Point

A calculated MW value representing the expected MW output of a Generation Resource ramping to a SCED Base Point.

Updated Network Model

A computerized representation of the ERCOT physical network topology, including some Resource Parameters, all of which replicates the forecasted or current network topology of the ERCOT System needed by ERCOT to perform its functions.

Usage Profile (*see* Load Profile)

USD

U.S. dollar.

V

Verbal Dispatch Instruction (VDI)

A Dispatch Instruction issued orally.

Voltage Profile

The normally desired predetermined distribution of desired nominal voltage set points across the ERCOT System.

Voltage Support Service

An Ancillary Service that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits.

W

Weather Zone

A geographic region designated by ERCOT in which climatological characteristics are similar for all areas within such region.

Wholesale Customer

A Non-Opt-In Entity receiving service at wholesale points of delivery from an LSE other than itself.

Wind-powered Generation Resource (WGR) (see Resource)

Wind-powered Generation Resource Production Potential (WGRPP)

The generation in MWh per hour from a WGR that could be generated from all available units of that Resource allocated from the 80% probability of exceedance of the Total ERCOT Wind Power Forecast.

X

Y

Z

2.2 ACRONYMS AND ABBREVIATIONS

ACE	Area Control Error
ALA	Applicable Legal Authority
AML	Adjusted Metered Load
ADR	Alternative Dispute Resolution
AVR	Automatic Voltage Regulator
AREP	Affiliated Retail Electric Provider
BLT	Block Load Transfer
CAO	Control Area Operator
CEII	Critical Energy Infrastructure Information
CEO	Chief Executive Officer
CFE	Comision Federal de Electricidad
CIM	Common Information Model
COP	Current Operating Plan
CPT	Central Prevailing Time
CR	Competitive Retailer
CRR	Congestion Revenue Right
CSA	Continuous Service Agreement
DAM	Day-Ahead Market
DAS	Data Aggregation System

DC Tie	Direct Current Tie
DLC	Direct Load Control
DLF	Distribution Loss Factor
DRUC	Day-Ahead Reliability Unit Commitment
DSP	Distribution Service Provider
DSR	Dynamically Scheduled Resource
DUNS	Data Universal Numbering System
DUNS #	DUNS Number
EC	Electric Cooperative
ECI	Element Competitiveness Index
EECP	Emergency Electric Curtailment Plan
EILS	Emergency Interruptible Load Service
EPRI	Electric Power Research Institute
EPS	ERCOT-Polled Settlement Meter
ERCOT	Electric Reliability Council of Texas, Inc.
ESI ID	Electric Service Identifier
FGR	Flowgate Right
FIP	Fuel Index Price
FOP	Fuel Oil Price
GTL	Generic Transmission Limit
HASL	High Ancillary Service Limit
HDL	High Dispatch Limit
HE	Hour Ending
HEL	High Emergency Limit
HRUC	Hourly Reliability Unit Commitment
HSL	High Sustained Limit
Hz	Hertz
IDR	Interval Data Recorder
IMM	Independent Market Monitor
IRR	Intermittent Renewable Resources
kV	Kilovolt
LASL	Low Ancillary Service Limit
LDL	Low Dispatch Limit
LEL	Low Emergency Limit
LFC	Load Frequency Control
LMP	Locational Marginal Price
LPC	Low Power Consumption
LSL	Low Sustained Limit
LTLF	Long-Term Load Forecast

LSE	Load Serving Entity
MAP	Mitigation Action Plan
MDAS	Meter Data Acquisition System
MCFRI	McCamey Flowgate Right
MCPC	Market Clearing Price for Capacity
MIS	Market Information System
MMBtu	Million British Thermal Units
MOU	Municipally Owned Utility
MPC	Maximum Power Consumption
MRE	Meter Reading Entity
MTLF	Mid-Term Load Forecast
MVAr	Mega Volt-Amperes reactive
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NOIE	Non-Opt-In Entity
Non-Spin	Non-Spinning Reserve
OCN	Operating Condition Notice
PCRR	Pre-Assigned Congestion Revenue Right
POLR	Provider of Last Resort
POS	Power Operating System
PRC	Physical Responsive Capability
PRR	Protocol Revision Request
PTB	Price-to-Beat
PTP	Point-to-Point
QF	Qualifying Facility
QSE	Qualified Scheduling Entity
RAP	Remedial Action Plan
RDF	Reserve Discount Factor
REC	Renewable Energy Credit
Reg-Down	Regulation Down
Reg-Up	Regulation Up
REP	Retail Electric Provider
RID	Resource ID
RIDR	Representative IDR
RMR	Reliability Must-Run
RPP	Renewable Production Potential
RPS	Renewable Portfolio Standard
RRS	Responsive Reserve
RTM	Real-Time Market

RUC	Reliability Unit Commitment
SASM	Supplemental Ancillary Services Market
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SE	State Estimator
STLF	Short-Term Load Forecast
SWCAP	System-Wide Offer Cap
TAC	Technical Advisory Committee
TDSP	Transmission and/or Distribution Service Provider
Texas SET	Texas Electronic Transaction
TOUS	Time Of Use Schedule
TSP	Transmission Service Provider
UFE	Unaccounted For Energy
URL	Unit Reactive Limit
VAr	Volt-Ampere reactive
VDI	Verbal Dispatch Instruction
WGR	Wind-powered Generation Resource

ERCOT Nodal Protocols

Section 3: Management Activities for the ERCOT System

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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3 MANAGEMENT ACTIVITIES FOR THE ERCOT SYSTEM

This section focuses on the management activities, including Outage Coordination, Resource Adequacy, Load forecasting, transmission operations and planning, and contracts for Ancillary Services for the ERCOT System.

3.1 Outage Coordination

"Outage Coordination" is the management of Transmission Facilities Outages and Resource Outages in the ERCOT System. Facility owners are solely and directly responsible for the performance of all maintenance, repair, and construction work, whether on energized or de-energized facilities, including all activities related to providing a safe working environment.

3.1.1 Role of ERCOT

(1) ERCOT shall coordinate and use reasonable efforts, consistent with Good Utility Practice, to accept, approve or reject all Outage schedules for maintenance, repair, and construction of both Transmission Facilities and Resources within the ERCOT System. ERCOT may reject an Outage schedule under certain circumstances, as set forth in Section 3.1.5.6, Rejection Notice; Section 3.1.6, Outages of Resources Other Than Reliability Resources; and Section 3.1.7, Reliability Resource Outages.

(2) ERCOT's responsibilities with respect to Outage Coordination include:

(a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) in coordination with and based on information regarding all Entities' Planned Outages and Maintenance Outages;

(b) Assessing the adequacy of available Resources, based on planned and known Resource Outages, relative to forecasts of Load, Ancillary Service requirements, and reserve requirements;

(c) Coordinating and approving or rejecting schedules for Planned Outages of Resources scheduled to occur within eight days after request;

(d) Coordinating and approving or rejecting schedules for Planned Outages of RMR Units under the terms of the applicable RMR Agreements;

(e) Coordinating and approving or rejecting Outages associated with Black Start Units under the applicable Black Start Unit Agreements;

(f) Reviewing and coordinating changes to existing 12-month Resource Outage plans to determine how changes will affect ERCOT System Reliability, including Resource Outages not previously included in the plan;

(g) Monitoring how Planned Outage schedules compare with actual Outages;

(h) Posting all proposed and approved schedules for Planned Outages and Maintenance Outages of Transmission Facilities on the Market Information System (MIS) Secure Area under Section 3.1.5.13, Transmission Report;

(i) Creating aggregated schedules of Planned Outages for Resources and posting those schedules on the MIS Secure Area under Section 3.2.3, System Adequacy Report;

(j) Monitoring Transmission Facilities and Resource Forced Outages and Maintenance Outages of immediate nature and implementing responses to those Outages as provided in these Protocols;

(k) Establishing and implementing communication procedures:

  (i) for a TSP to request approval of Transmission Facilities Planned Outage and Maintenance Outage schedules; and

  (ii) for a Resource Entity's designated Single Point of Contact to submit Outage plans and to coordinate Resource Outages;

(l) Establishing and implementing record-keeping procedures for retaining all requested Planned Outages, Maintenance Outages, and Forced Outages;

(m) Planning and analyzing Transmission Facilities Outages; and

(n) Working with the appropriate TAC Subcommittee to develop procedures for characterizing a Simple Transmission Outage.

3.1.2 Planned Outage or Maintenance Outage Data Reporting

Each Resource Entity and Transmission Service Provider (TSP) shall use reasonable efforts, consistent with Good Utility Practice, to continually update its Outage schedule. All information submitted about Planned Outages or Maintenance Outages must be submitted by the Resource Entity or the TSP under this Section. If an Outage schedule for a Resource is also applicable to the COP, the QSE responsible for the Resource shall also update the COP to provide the same information describing the Outage.

3.1.3 Rolling 12-Month Outage Planning and Update

3.1.3.1 Transmission Facilities

(1) Each TSP shall provide to ERCOT a Planned Outage or Maintenance Outage plan in an ERCOT-provided format for the next 12 months updated monthly. Planned Outage or Maintenance Outage scheduling data for Transmission Facilities must be kept current.

Updates must identify all changes to any previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outage anticipated over the next 12 months. ERCOT shall coordinate in-depth reviews of the 12-month plan with each TSP at least twice per year.

(2) ERCOT shall report statistics on how TSP Planned Outages compare with actual TSP Outages, post those statistics to the MIS Secure Area, and report those statistics to ERCOT subcommittees twice per year. However, to the extent Outages are required to repair or improve telemetry accuracy or failures, the Outage must not be counted against the TSP in its performance of planning Outages, because such Outages cannot reasonably be forecasted 12 months in advance.

3.1.3.2 Resources

(1) Each Resource Entity shall provide to ERCOT a Planned Outage and Maintenance Outage plan in an ERCOT-provided format for the next 12-months updated monthly. Planned Outage and Maintenance Outage scheduling data for Resource Facilities must be kept current. Updates, through an electronic interface as specified by ERCOT, must identify any changes to previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outages anticipated over the next 12 months.

(2) ERCOT shall report statistics monthly on how Resource Planned Outages compare with actual Resource Outages, and post those statistics to the MIS Secure Area.

3.1.4 Communications Regarding Resource and Transmission Facilities Outages

3.1.4.1 Single Point of Contact

(1) All communications concerning a Planned Outage or Maintenance Outage must be between ERCOT and the designated "Single Point of Contact" for each TSP or Resource Entity. All nonverbal communications concerning Planned Outages must be conveyed through an electronic interface as specified by ERCOT. The TSP or Resource Entity shall identify, in its initial request or response, the Single Point of Contact, with primary and alternate means of communication. The Resource Entity or TSP shall submit a Notice of Change of Information (NCI) form when changes occur to a Single Point of Contact. This identification must be confirmed in all communications with ERCOT regarding Planned Outage or Maintenance Outage requests.

(2) The Single Point of Contact must be either a person or a position available seven days per week and 24 hours per day for each Resource Entity and TSP. The Resource Entity shall designate its QSE as its Single Point of Contact. The Single Point of Contact for the TSP must be designated under the ERCOT Operating Guides.

3.1.4.2 Method of Communication

ERCOT, each TSP, and each Resource Entity shall communicate according to ERCOT procedures under these Protocols. All submissions, changes, approvals, rejections, and withdrawals regarding Outages must be processed through the ERCOT Outage Scheduler on the ERCOT programmatic interface, except for Forced Outages and Maintenance Level I Outages, which must be communicated to ERCOT immediately via the Current Operating Plan if submitted for a Resource and using the Outage Scheduler if submitted by a TSP. This does not prohibit any verbal communication when the situation warrants it. ERCOT shall develop guidelines for the types of events that may require verbal communication.

3.1.4.3 Reporting for Planned Outages and Maintenance Outages of Resource and Transmission Facilities

(1) Each Resource Entity and TSP shall submit information regarding proposed Planned Outages and Maintenance Outages under procedures adopted by ERCOT. The obligation to submit that information applies to each Resource Entity that is responsible to operate or maintain a Resource that is part of or that affects the ERCOT System. The obligation to submit that information applies to each TSP that is responsible to operate or maintain Transmission Facilities that are part of or affect the ERCOT System. A Resource Entity or TSP is also obligated to submit information for Transmission Facilities or Resources that are not part of the ERCOT System or that do not affect the ERCOT System if that information is required for regional security coordination as determined by ERCOT.

(2) Before taking an RMR or Black Start Resource (“Reliability Resources”) out of service for a Planned Outage or Maintenance Outage, the Single Point of Contact for that Reliability Resource must obtain ERCOT’s approval of the schedule of the Planned Outage or Maintenance Outage. ERCOT shall review and approve or reject each proposed Planned Outage or Maintenance Outage schedule under this Section and the applicable Agreements.

3.1.4.4 Communicating Rejection of Proposed Resource Outages

(1) This subsection applies to certain proposed Resource Outages submitted eight days or less prior to the Outage start date that are either:

(a) proposed changes to Planned Outages; or

(b) newly-proposed Resource Outages.

(2) If a proposal under paragraph (1) above (“Proposed Short-Noticed Resource Outage”), in conjunction with Outages that have been previously approved or accepted, would cause a violation of applicable reliability standards, ERCOT shall communicate with the requesting Market Participant and each other Market Participant with a relevant Outage that was previously approved or accepted to try to identify how to adjust any of the proposed and approved or accepted Outages.

3.1.4.5 Management of Resource or Transmission Forced Outages or Maintenance Outages

(1) In the event of a Forced Outage, after the affected equipment is removed from service, the Resource Entity or QSE, as appropriate, or TSP must notify ERCOT as soon as practicable of its action by:

(a) For Resource Outages:

(i) changing the telemetered Resource Status appropriately, including a text description when it becomes known, of the cause of the Forced Outage; and

(ii) updating the Current Operating Plan; and

(iii) updating the Outage Scheduler, if necessary.

(b) For Transmission Facilities Forced Outages:

(i) changing the telemetered status of the affected Transmission Elements; and

(ii) updating the Outage Scheduler with the expected return-to-service time.

(2) Forced Outages may require ERCOT to review and withdraw approval of previously approved or accepted, as applicable, Planned Outage or Maintenance Outage schedules to ensure reliability.

(3) For Maintenance Outages, the Resource Entity or QSE, as appropriate, or TSP shall notify ERCOT of any Resource or Transmission Facilities Maintenance Outage according to the Maintenance Outage Levels by updating the Current Operating Plan and Outage Scheduler. ERCOT shall coordinate the removal of facilities from service within the defined timeframes as specified by the TSP, QSE or Resource Entity in its notice to ERCOT.

(4) ERCOT may require supporting information describing Forced Outages and Maintenance Outages. ERCOT may reconsider and withdraw approvals of other previously approved Transmission Facilities Outage or an Outage of a Reliability Resource as a result of Forced Outages or Maintenance Outages, if necessary, in ERCOT’s determination to protect system reliability. When ERCOT approves a Maintenance Outage, ERCOT shall coordinate timing of the appropriate course of action under these Protocols.

(5) Removal of a Resource or Transmission Facilities from service under Maintenance Outages must be coordinated with ERCOT. To minimize harmful impacts to the system in urgent situations, the equipment may be removed immediately from service, provided notice is given immediately, by the Resource Entity or TSP, to ERCOT of such action.

3.1.4.6 Notice of Forced Outage or Unavoidable Extension of Planned or Maintenance Outage Due to Unforeseen Events

(1) If a Planned or Maintenance Outage is not completed within the ERCOT-approved timeframe and the Transmission Facilities or Resources are in such a condition that they cannot be restored at the Outage schedule completion date, the requesting party shall submit to ERCOT a Forced Outage (unavoidable extension) form describing the extension of the Outage and providing a revised return date.

(2) Any Forced Outage that occurs in Real-Time must be entered into the Outage Scheduler if it is to remain an Outage for longer than two hours.

3.1.4.7 Outage Coordination of Forecasted Emergency Conditions

(1) If ERCOT forecasts an inability to meet applicable reliability standards and it has exercised all other reasonable options, ERCOT shall inform the Single Point of Contact for any affected Market Participant and all QSEs verbally and in electronic form by declaring an Emergency Condition according to Section 6.5.9.3, Communication Under Emergency Conditions.

(2) Under an Emergency Condition and if ERCOT cannot meet applicable reliability standards, ERCOT may discuss the reliability problem with Resource Entities, TSPs, and DSPs to reach mutually agreeable solutions where Outages are negatively affecting system reliability. Actions may include changes to Outage schedules and the Current Operating Plan.

3.1.4.8 Deratings

The Resource Entity or its designee must enter material deratings that are expected to last more than 48 hours in the ERCOT Outage Scheduler. A derating is considered to be material when the Resource's capability is reduced by the greater of 10% or 10 MW due to the loss of auxiliary equipment or other known conditions. ERCOT will consider the Resource's capability as the lesser of the latest seasonal Net Dependable Capability test, or the asset registration submittal.

3.1.5 Transmission System Outages

3.1.5.1 ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities

(1) A TSP shall request a Planned Outage or Maintenance Outage for any Transmission Element in the Network Operations Model that requires the Transmission Element to be removed from its normal service. Planned Outages or Maintenance Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP enters the breaker and switch statuses associated with an

Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP in accordance with this Section constitutes a request for ERCOT's approval of the Outage schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests.

(2) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules according to Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests. ERCOT shall transmit its approvals and rejections to TSPs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of Approval and Rescheduling of Approved Planned Outages and Maintenance Outages of Transmission Facilities.

3.1.5.2 Receipt of TSP Requests by ERCOT

ERCOT shall acknowledge each request for approval of a Transmission Planned Outage schedule within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the TSP regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Transmission Facilities.

3.1.5.3 Timelines for Response by ERCOT for TSP Requests

(1) For Transmission Facilities Outages, ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between the request for approval of the proposed Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
Three days	1800 hours, two days before the start of the proposed Outage
Between four and eight days	1800 hours, three days before the start of the proposed Outage
Between nine days and 45 days	Four days before the start of the proposed Outage
Between 46 and 90 days	30 days before the start of the proposed Outage
Greater than 90 days	75 days before the start of the proposed Outage

(2) For Outages scheduled at least three days before the scheduled start date of the proposed Outage, ERCOT shall make reasonable attempts to accommodate unusual circumstances that support TSP requests for approval earlier than required by the schedule above.

(3) If circumstances prevent adherence to these timetables, ERCOT shall discuss the request status and reason for the delay of the approval with the requesting TSP and make reasonable attempts to mitigate the effect of the delay on the TSP.

(4) When ERCOT rejects a request for an Outage, ERCOT shall provide the TSP, in written or electronic form, suggested amendments to the schedules of a Planned Outage or Maintenance Outage of Transmission Facilities. Any such suggested amendments accepted by the TSP must be processed by ERCOT as a Planned Outage or Maintenance Outage of Transmission Facilities request under this Section.

3.1.5.4 Delay

ERCOT may delay its approval or rejection of a proposed Planned Outage or Maintenance Outage of a Transmission Facilities schedule if the requesting TSP has not submitted sufficient or complete information within the time frames set forth in these Protocols.

3.1.5.5 Opportunity Outage of Transmission Facilities

Opportunity Outages of Transmission Facilities may be approved under Section 3.1.6.8, Opportunity Outage.

3.1.5.6 Rejection Notice

(1) If ERCOT rejects a request, ERCOT shall provide the TSP a written or electronic rejection notice that includes:

(a) Specific concerns causing the rejection;

(b) Possible remedies or transmission schedule revisions, if any that might mitigate the basis for rejection; and

(c) An electronic copy of the ERCOT study case for review by the TSP.

(2) ERCOT may reject a Planned Outage or Maintenance Outage of Transmission Facilities only:

(a) To protect system reliability or security;

(b) Due to insufficient information regarding the Outage; or

(c) Due to failure to comply with submittal process requirements, as specified in these Protocols.

(3) When multiple proposed Planned Outages or Maintenance Outages cause a reliability or security concern, ERCOT shall:

(a) Communicate with each TSP to see if the TSP will adjust its proposed Planned Outage or Maintenance Outage schedule;

(b) Determine if each TSP will agree to an alternative Outage schedule; or

(c) Reject, in ERCOT's sole discretion, one or more proposed Outages, considering order of receipt and impact on the ERCOT Transmission Grid.

3.1.5.7 Withdrawal of Approval and Rescheduling of Approved Planned Outages and Maintenance Outages of Transmission Facilities

(1) If ERCOT believes it cannot meet the applicable reliability standards and has exercised reasonable options, ERCOT may contact the TSP for more information prior to its withdrawal of the approval for a Planned Outage or Maintenance Outage schedule. ERCOT shall inform the affected TSP both orally and in written or electronic form as soon as ERCOT identifies a situation that may lead to the withdrawal of ERCOT's approval. If ERCOT withdraws its approval, the TSP may submit a new request for approval of the Planned Outage or Maintenance Outage schedule provided the new request meets the submittal requirements for Outage Scheduling. If ERCOT withdraws approval of Planned Outages and Maintenance Outages of Transmission Facilities, ERCOT shall post notice through the MIS Secure Area as soon as practicable but not later than one hour of the change to inform Market Participants.

(2) In determining whether to withdraw approval, ERCOT shall duly consider whether the Planned Outage or Maintenance Outage affects public infrastructure if ERCOT is made aware of such potential impacts by the TSP (e.g., impacts on highways, ports, municipalities, and counties).

3.1.5.8 Priority of Approved Planned Outages

In considering TSP requests, ERCOT shall give priority to approved Planned Outage and Maintenance Outage schedules previously posted to the MIS Secure Area.

3.1.5.9 Information for Inclusion in Transmission Facilities Outage Requests

Transmission Facilities Outage requests submitted by a TSP must include the following Transmission Facilities-specific information:

(a) The identity of the Transmission Facilities, in the Network Operations Model, including TSP and location;

(b) The nature of the work, by predefined classifications, to be performed during the proposed Transmission Facilities Outage;

(c) The preferred start and finish dates for the proposed Transmission Planned or Maintenance Outage;

(d) The time required to: (i) finish the Transmission Planned Outage or Maintenance Outage and (ii) restore the Transmission Facilities to normal operation;

(e) Primary and alternate telephone numbers for the TSP's Single Point of Contact, as described in Section 3.1.4.1, Single Point of Contact, and the name of the individual submitting the information;

(f) The scheduling flexibility (i.e., the earliest start date and the latest finish date for the Outage);

(g) Any Transmission Facilities that must be out of service to facilitate the TSP's request;

(h) Any remedial actions or special protection systems necessary during the Outage and the contingency that would require the remedial action or relay action; and

(i) Any other relevant information related to the proposed Outage or any unusual risks affecting the schedule.

3.1.5.10 Additional Information Requests

The requesting TSP shall comply with any ERCOT requests for more information about, or for clarification of, the information submitted by the TSP for a proposed Outage.

3.1.5.11 Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests

(1) ERCOT shall evaluate requests, approve, or reject Transmission Facilities Planned Outages and Maintenance Outages according to the requirements of this section. ERCOT may approve Outage requests provided the Outage in combination with other proposed Outages does not cause a violation of applicable reliability standards. ERCOT shall reject Outage requests that do not meet the submittal timeline specified in Section 3.1.5.12, Submittal Timeline for Transmission Facility Outage Requests. ERCOT shall consider the following factors in its evaluation:

(a) Forecasted conditions during the time of the Outage;

(b) Outage plans submitted by Resource Entities and TSPs under Section 3.1, Outage Coordination;

(c) Forced Outages of Transmission Facilities;

(d) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software;

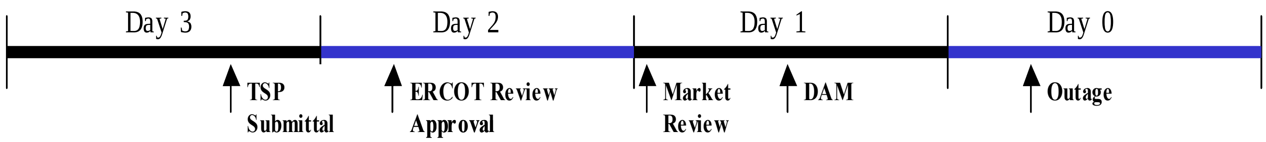
(e) Previously approved Planned Outages and Maintenance Outages;

(f) Impacts on the transfer capability of DC Ties; and

(g) Good Utility Practice for Transmission Facilities maintenance.

(2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP.

3.1.5.12 Submittal Timeline for Transmission Facility Outage Requests



TSPs shall submit all requests for Planned Outages and Maintenance Outages or changes to existing approved Outages of Transmission Elements in the Network Operations Model to ERCOT no later than the minimum amount of time between the submittal of a request to ERCOT for approval of a proposed Outage and the scheduled start date of the proposed Outage, according to the following table:

Type of Outage	**Minimum amount of time between the Outage request and the scheduled start date of the proposed Outage:**	**Minimum amount of time between any change to an Outage request and the scheduled end date an existing Outage:**
Forced Outage	Immediate	Immediate
Maintenance Outage Level I	Immediate	Immediate
Maintenance Outage Level II	Two days [1]	Two days [1]
Maintenance Outage Level III	Three days	Three days
Planned Outage	Three days	Three days
Simple Transmission Outage	One day	One day

Note:

1. For reliability purposes, ERCOT may reduce to one day on a case-by-case basis.

3.1.5.13 Transmission Report

ERCOT shall post on the MIS Secure Area:

(a) All proposed Transmission Facilities Outages that have not yet been approved or rejected within one hour of receipt by ERCOT; and

(b) Any approved, accepted or rejected Transmission Facilities Outage within one hour of approval, acceptance or rejection of the Outage.

3.1.6 Outages of Resources Other than Reliability Resources

(1) ERCOT shall accept all Outage schedules and changes to Outage schedules for a Resource other than a Reliability Resource submitted to ERCOT more than eight days before the proposed start date of the Outage.

(2) If a Resource Entity plans to start a Planned or Maintenance Outage within eight days that has not been previously included in the Resource's written Planned Outage and Maintenance Outage plan, then the Resource Entity must immediately notify ERCOT and include in its notice whether the Outage is a Forced Outage, Maintenance (Level I, II, or III) Outage, or Planned Outage. ERCOT's response to this notification must comply with these requirements:

(a) ERCOT shall accept Forced and Levels I, II, and III Maintenance Outages proposals, and ERCOT shall coordinate the Outages within the time frames specified in these Protocols.

(b) ERCOT shall accept Planned Outage proposals, except that ERCOT shall reject an Outage proposal if it will impair ERCOT's ability to meet applicable reliability standards and other solutions cannot be exercised.

(c) ERCOT shall accept Forced and Maintenance Outage plans from a Qualifying Facility (QF) that result from the outage of the QF's thermal host facility.

3.1.6.1 Receipt of Resource Requests by ERCOT

ERCOT shall acknowledge each request for approval of a Resource Planned Outage schedule within two Business Hours of the receipt of the request. ERCOT may request additional information or seek clarification from the Resource Entity regarding the information submitted for a proposed Planned Outage or Maintenance Outage for Resource Facilities.

3.1.6.2 Resources Outage Plan

(1) Resource Entity Outage requests shall include the following information:

(a) The primary and alternate phone number of the Resource Entity's Single Point of Contact for Outage Coordination;

(b) The Resource identified by the name in the Network Operations Model;

(c) The net megawatts of capacity the Resource Entity anticipates will be available during the Outage (if any);

(d) The estimated start and finish dates for each Planned and Maintenance Outage;

(e) An estimate of the acceptable deviation in the Outage schedule (i.e., the earliest start date and the latest finish date for the Outage); and

(f) The nature of work to be performed during the Outage.

(2) When ERCOT accepts a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action within the Resource-specified timeframe. The QSE shall notify ERCOT of the Outage and coordinate the time.

3.1.6.3 Additional Information Requests

ERCOT may request additional information from a Resource Entity regarding the information submitted as part of a Resource Outage plan. ERCOT may not unnecessarily delay requests for information in terms of the required response time.

3.1.6.4 Approval of Changes to a Resource Outage Plan

(1) ERCOT shall accept all changes to a Resource Outage plan submitted by a Resource Entity more than eight days before the planned start date for the Outage. ERCOT may discuss with Resource Entities or QSEs any Outage requests that are expected to result in a violation of an ERCOT reliability criteria or that may result in cancellation of a Transmission Facilities Planned Outage in an attempt to reach a mutually agreeable resolution, including rescheduling the Outage in a manner agreeable to the Resource Entity.

(2) A Resource Entity must request approval from ERCOT only for new Resource Outages or changes to a previously accepted planned Resource Outage scheduled to occur within eight days of the request.

(3) ERCOT shall approve Planned Outage and Maintenance Outage requests to occur within eight days, except that ERCOT shall reject proposals if the Outage proposal will impair ERCOT's ability to meet applicable reliability standards.

(4) When the scheduled work is complete, any Resource may return from a Planned Outage in accordance with Section 3.1.6.9, Outage Returning Early. ERCOT shall accept this change and, in the event that a Transmission Facilities Outage was scheduled concurrently with the affected Resource(s) Outage, ERCOT shall coordinate between the TSP and the Resource Entity to schedule a time mutually agreeable to both parties for the Resource to be On-Line. If mutual agreement cannot be reached, then ERCOT shall decide, considering expected impact on system security, future Outage plans, and participants.

3.1.6.5 Evaluation of Proposed Short-Noticed Resource Outage

(1) If a Proposed Short-Noticed Resource Outage, in conjunction with previously accepted Outages, would cause a violation of applicable reliability standards, ERCOT shall:

(a) Communicate with the requesting Market Participant and each other Market Participants as required under Section 3.1.4.4, Communicating Rejection of Proposed Resource Outages; and

(b) Consider modifying the previous acceptance or approval of one or more Transmission Facilities or Reliability Resource Outages, considering order of receipt and impact to the ERCOT System; based upon security and reliability analysis results, ERCOT shall investigate possible Remedial Action Plans for all insecure states and strive to maximize transmission usage consistent with reliable operation;

(2) If security can be maintained using an alternative considered in item (1)(b), then ERCOT, may, in its judgment, direct the selected alternatives and approve the Proposed Short-Noticed Resource Outage.

(3) If ERCOT does not resolve the security issues using any alternatives considered in item (1)(b), then ERCOT shall reject the Proposed Short-Noticed Resource Outage.

3.1.6.6 Timelines for Response by ERCOT for Resource Outages

ERCOT shall approve, accept or reject each request in accordance with the following table:

Amount of time between a Request for acceptance of a Planned Outage and the scheduled start of the proposed Outage:	**ERCOT shall approve, accept or reject no later than:**
Between one and two days	ERCOT shall approve or reject within eight Business Hours of receipt by ERCOT
Between three and eight days	ERCOT shall approve or reject within 1800 hours, two days prior to the start of the proposed Outage
Greater than eight days	ERCOT must accept, but ERCOT may discuss reliability and scheduling impacts to minimize hazard/cost to ERCOT System in an attempt to accomplish minimum overall impact.

3.1.6.7 Delay

ERCOT may delay its acceptance, approval or rejection of a proposed Planned Outage schedule if the requesting Resource Entity has not submitted sufficient or complete information within the time frames set forth in this Section 3.1.6, Outages of Resources Other Than Reliability Resources. Review periods for Planned Outage consideration do not commence until sufficient and complete information is submitted to ERCOT as described in Section 3.1.6.2, Resources Outage Plan.

3.1.6.8 Opportunity Outage

(1) Opportunity Outages for Resources are a special category of Planned Outages that may be approved by ERCOT when a specific Resource has been forced Off-Line due to a Forced Outage and the Resource has been previously accepted for a Planned Outage during the next eight days.

(2) When a Forced Outage occurs on a Resource that has an accepted or approved Outage scheduled within the following eight days, the Resource may remain Off-Line and start the accepted or approved Outage earlier than scheduled. The QSE must give as much notice as practicable to ERCOT.

(3) Opportunity Outages of Transmission Facilities may be approved by ERCOT when a specific Resource is Off-Line due to a Forced, Planned or Maintenance Outage. A TSP may request an Opportunity Outage at any time.

(4) When an Outage occurs on a Resource that has an approved Transmission Facilities Opportunity Outage request on file, the TSP may start the approved Outage as soon as practical after receiving authorization to proceed by ERCOT. ERCOT must give as much notice as practicable to the TSP.

3.1.6.9 Outage Returning Early

(1) A Resource that completes a Planned Outage early and wants to resume operation shall notify ERCOT of the early return prior to resuming service by making appropriate entries in the Current Operating Plan or Outage Scheduler if applicable as much in advance as practicable, but not later than at least two hours prior to beginning startup. Within two hours of receiving such request, ERCOT shall either:

(a) Approve the request unless, as a result of complying with the request, ERCOT cannot maintain system reliability or security with the Resource injection. In such a case, ERCOT shall issue a Verbal Dispatch Instruction to the Resource's QSE to stay Off-Line; or

(b) Coordinate between the TSP and Resource Entity to schedule a time agreeable to both parties for the Resource to be Off-Line in the event if that a Transmission Facilities Outage requires the affected Resource to be Off-Line. If mutual agreement is not reached, then ERCOT shall decide on the appropriate time, after considering expected impacts on system security, future Outage plans, and participants and issue a Verbal Dispatch Instruction to the Resource's QSE to stay Off-Line.

(2) Before an early return from an Outage, a Resource Entity or QSE may inquire of ERCOT whether the Resource is expected to be decommitted by ERCOT upon its early return. If a Resource Entity or QSE is notified by ERCOT that the Resource will be decommitted if it returns early and the Resource Entity or QSE starts the Resource within the previously accepted or approved Outage period, then the QSE representing the Resource will not be paid any decommitment compensation as otherwise would be provided for in Section 5.7, Settlement for RUC Process.

3.1.6.10 Resource Coming On-Line

Before start-up and synchronizing On-Line, a Resource Entity or QSE may inquire of ERCOT whether the Resource is expected to be decommitted by ERCOT upon its coming On-Line. If a Resource Entity or QSE is notified by ERCOT that the Resource will be decommitted if the Resource comes On-Line and the Resource Entity or QSE starts the Resource, then the QSE representing the Resource will not be paid any decommitment compensation as otherwise would be provided for in Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource.

3.1.7 Reliability Resource Outages

ERCOT shall evaluate requests for approval of an Outage of a Reliability Resource to determine if any one or a combination of proposed Outages may cause ERCOT to violate applicable reliability standards. ERCOT's evaluations shall take into consideration factors including the following:

(a) Load forecast;

(b) All other known Outages; and

(c) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software.

3.1.7.1 Timelines for Response by ERCOT on Reliability Resource Outages

(1) ERCOT shall approve requests for Planned Outages of Reliability Resources unless, in ERCOT's determination, the requested Planned Outage would cause ERCOT to violate applicable reliability standards. ERCOT shall approve or reject each request in accordance with the following table:

Amount of time between a Request for approval of a proposed Planned Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
No less than 30 days	15 days before the start of the proposed Outage
Greater than 45 days	30 days before the start of the proposed Outage

(2) ERCOT shall approve requests for Outages, other than Forced Outages or Level I Maintenance Outages, of Reliability Resources unless, in ERCOT's determination, the requested Outage would cause ERCOT to violate applicable reliability standards. ERCOT shall approve or reject Maintenance Outages on Reliability Resources as follows:

Amount of time between a Request for approval of a proposed Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
Between three and eight days	0000 hours, two days before the start of the proposed Outage
Between nine and 30 days	Four days before the start of the proposed Outage

(3) ERCOT shall not be deemed to have approved the Outage request associated with the Planned Outage until ERCOT notifies the Single Point of Contact of its approval. ERCOT shall transmit approvals electronically.

3.1.7.2 Changes to an Approved Reliability Resource Outage Plan

Once ERCOT has approved a Reliability Resource Planned Outage, the Resource Entity for the Reliability Resource may submit to ERCOT a change request by entering the change in the Outage Scheduler no later than 30 days before the scheduled start date of the approved Outage. ERCOT shall approve or reject the proposed change within 15 days of receiving the change request form. ERCOT may, at its discretion, relax the 30 day Notice requirement.

3.2 Analysis of Resource Adequacy

3.2.1 Calculation of Aggregate Resource Capacity

(1) ERCOT shall use Outages in the Outage Scheduler and the Resource Status from the COP to calculate the aggregate capacity from Generation Resources and Load Resources projected to be available in the ERCOT Region and in Forecast Zones in ERCOT. "Forecast Zones" have the same boundaries as the 2003 ERCOT Congestion Management Zones. Each Resource will be mapped to a Forecast Zone during the registration process.

(2) On a rolling 36-month basis, ERCOT shall calculate the aggregate weekly Generation Resource capacity and Load Resource capacity in the ERCOT Region and the Forecast Zones projected to be available during the ERCOT Region peak Load hour of each week for the following 36 months, starting with the second week.

(3) On a rolling hourly basis, ERCOT shall calculate the aggregate hourly Generation Resource capacity and Load Resource capacity in the ERCOT Region and Forecast Zones projected to be available during each hour for the following seven days.

(4) Projections of Generation Resource capacity from Wind Generation Resources (WGRs) shall be consistent with that capacity forecasted in Section 3.13, Renewable Production Potential Forecasts.

3.2.2 Demand Forecasts

(1) ERCOT shall develop and publish monthly on the MIS Secure Area peak Demand forecasts by Forecast Zone for each week, starting with the second week for the next 36 months using the 36-Month Load Forecast as described in Section 3.12, Load Forecasting. During the development of this forecast, ERCOT may consult with QSEs, TSPs, and other Market Participants that may have knowledge of potential Load growth.

(2) ERCOT may, at its discretion, publish on the MIS additional peak Demand analyses for periods beyond 36 months.

(3) ERCOT shall develop and publish hourly on the MIS Secure Area peak Demand forecasts by Forecast Zone for each hour of the next seven days using the Seven-Day Load Forecast as described in Section 3.12.

(4) For purposes of Demand forecasting, ERCOT may choose to use the same forecast as that used for the Load forecast.

3.2.3 System Adequacy Reports

ERCOT shall publish system adequacy reports to assess the adequacy of Resources and Transmission Facilities to meet the projected Demand. ERCOT shall provide reports on a system-wide basis and by Forecast Zone

(1) ERCOT shall generate and post a "Medium-Term System Adequacy Report" on the MIS Secure Area. ERCOT shall update the report monthly using the latest aggregate Generation Resource capacity and Load Resource capacity. The data will be provided for each week, starting with the second week, of a rolling 36-month period. The Medium-Term System Adequacy Report will provide:

(a) Generation Resource capacity at the time of forecasted weekly peak Demand;

(b) Load Resource capacity at the time of the forecasted weekly peak Demand;

(c) Weekly peak forecast Demand described in Section 3.2.2, Demand Forecasts;

(d) Calculated system reserve, highlighting any deficiency hours that excludes Load Resource capacity;

(e) Calculated system reserve, highlighting any deficiency hours that includes Load Resource capacity shown as a reduction in forecast Demand;

(f) Ancillary Service requirements; and

(g) Transmission constraints that have a high probability of being binding in SCED or DAM given the forecasted system conditions for each week excluding the effects of any Transmission or Resource Outages.

(2) ERCOT shall generate and post a "Short-Term System Adequacy Report" on the MIS Secure Area. ERCOT shall update this report hourly following updates to the Seven-Day Load Forecast and on detection of a change to Resource Status that changes the availability of a Resource. The Short-Term System Adequacy Report will provide:

(a) For Generation Resources, the available On-Line Resource capacity for each hour, using the COP for the first seven days;

(b) For Load Resources, the available capacity for each hour using the COP;

(c) Forecast Demand for each hour described in Section 3.2.2, Demand Forecasts;

(d) Ancillary Service requirements for the Operating Day and subsequent days; and

(e) Transmission constraints that have a high probability of being binding in SCED or DAM given the forecasted system conditions for each week including the effects of any Transmission or Resource Outages. The binding constraints may not be updated every hour.

3.2.4 Statement of Opportunities

(1) ERCOT shall annually publish a "Statement of Opportunities" report that provides a projection of the capability of existing and planned Generation Resources, Load Resources, and Transmission Facilities to reliably meet ERCOT's projected needs. A Statement of Opportunities report published in even-numbered years shall use a ten-year study horizon and be published by December 31 of those years. A Statement of Opportunity report published in odd-numbered years shall use a five-year study horizon and be published on or around October 1 of those years. ERCOT shall prescribe reporting requirements for generation Entities and TSPs to report to ERCOT their plans for adding new facilities, upgrading existing facilities, and mothballing or retiring existing facilities. ERCOT also shall prescribe reporting requirements for Load Entities to report to ERCOT their plans for adding new Load Resources or retiring existing Load Resources.

(2) Prior to prescribing new reporting requirements for the development of the Statement of Opportunities, ERCOT shall use information already being provided by Market Participants if doing so is cost-effective.

3.3 Management of Changes to ERCOT Transmission Grid

Additions and changes to the ERCOT System must be coordinated with ERCOT to accurately represent the ERCOT Transmission Grid.

3.3.1 ERCOT Approval of New or Relocated Facilities

Before energizing and placing into service any new or relocated facility connected to the ERCOT Transmission Grid, a TSP, QSE, or Resource Entity shall enter appropriate information in the Outage Scheduler and coordinate with, and receive written notice of approval from, ERCOT.

3.3.2 Types of Work Requiring ERCOT Approval

Each TSP, QSE and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid:

(a) Transmission lines;

(b) Equipment including circuit breakers, transformers, disconnects, reactive devices, and wave traps;

(c) Resource interconnections; and

(d) Protection and control schemes, including changes to Remedial Action Plans (RAP), Supervisory Control and Data Acquisition (SCADA) systems, Energy Management Systems (EMS), AGC, or Special Protection Systems (SPS).

3.3.2.1 Information to Be Provided to ERCOT

The energization or removal of equipment in the Network Operations Model requires an entry into the Outage Scheduler by the TSP or Resource Entity. If any changes in system topology or telemetry are expected, then the TSP or Resource Entity shall notify ERCOT per the schedule in Section 3.3.1, ERCOT Approval of New or Relocated Facilities, and shall submit an NOMCR to include the following:

(a) Proposed energize date;

(b) TSP performing work;

(c) TSP(s) responsible for rating affected transmission element(s);

(d) Station identification code;

(e) Identification of existing Transmission Facilities involved and new Transmission Facilities (if any) being added or existing Transmission Facilities being permanently removed from service;

(f) Ratings of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(g) Outages required (clearly identify each Outage if multiple Outages are required), including sequence of Outage and estimate of Outage duration;

(h) General statement of work to be completed with intermediate progress dates and events identified;

(i) Supervisory Control and Data Acquisition modification work, including descriptions of the telemetry points or changes to existing telemetry, providing information on equipment being installed, changed, or monitored;

(j) Additional data determined by ERCOT and TSP(s) as needed to complete the ERCOT model representation of existing Transmission Facilities involved and new Transmission Facilities (if any) being added;

(k) Statement of completion, including:

    (i) Statement to be made at the completion of each intermediate stage of project; and

    (ii) Statement to be made at completion of total project.

(l) Drawings, including:

    (i) Existing status;

    (ii) Each intermediate stage; and

    (iii) Proposed final configuration.

3.3.2.2 Record of Approved Work

ERCOT shall maintain a record of all work approved in accordance with Section 3.3, Management of Changes to ERCOT Transmission Grid, and shall publish, and update monthly, information on the MIS Secure Area regarding each new Transmission Element to be installed on the ERCOT Transmission Grid.

3.4 Load Zones

ERCOT shall assign every Electrical Bus to a Load Zone for settlement purposes. ERCOT shall calculate a Settlement Point Price for each Load Zone as the Load-weighted average of the

LMPs at all Electrical Buses assigned to that Load Zone. The Load-weighting must be determined using the Load, if any, from the State Estimator at each Electrical Bus.

3.4.1 Load Zone Types

(1) The Load Zone types are:

(a) the Competitive Load Zones;

(b) the NOIE Load Zones created pursuant to Section 3.4.3, NOIE Load Zones; and

(c) the DC Tie Load Zones as defined in Section 3.4.4, DC Tie Load Zones.

(2) The Competitive Load Zones are the four zones in effect during the 2003 ERCOT market unless they are changed pursuant to Section 3.4.2, Load Zone Modifications, less any Electrical Buses that are assigned to a NOIE Load Zone or a DC Tie Load Zone.

3.4.2 Load Zone Modifications

Load Zones may be added, deleted, or changed, only when approved by the ERCOT Board, with the exception of Section 3.4.3, NOIE Load Zones, paragraph (2)(a). Approved additions, deletions, or changes go into effect 36 months after the end of the month in which the addition, deletion, or change was approved.

3.4.3 NOIE Load Zones

(1) A Non-Opt-In Entity (NOIE) or a group of NOIEs may establish a Load Zone in accordance with this Section.

(2) The descriptions and conditions set forth below apply to Load Zones established by NOIEs:

(a) All NOIEs must be assigned to an appropriate Competitive Load Zone, unless they had made a one-time choice to establish a NOIE Load Zone and notified ERCOT in writing of that choice six months before the Texas Nodal Market Implementation Date, except as specified otherwise in item (d) below;

(b) The number of NOIE Load Zones may not exceed 20;

(c) Any costs allocated based upon a zonal Load Ratio Share must be allocated using "Cost-Allocation Load Zones," which are the four zones in effect during the 2003 ERCOT market unless they are changed pursuant to Section 3.4.2, Load Zone Modifications. For each NOIE that has Load buses in more than one Cost-Allocation Load Zone, the allocation shall be based on the NOIE's Load in each Cost-Allocation Load Zone;

(d) Each group of NOIEs who are parties to the same pre-1999 power supply arrangements and that has a 2003 peak Load in excess of 2,300 MW and any other NOIE that has a 2003 peak Load in excess of 2,300 MW is automatically a separate NOIE Load Zone;

(e) ERCOT shall uniquely identify NOIE Load Zones. NOIEs may participate in only one NOIE Load Zone, and all Loads served by that NOIE must be contained within that Load Zone;

(f) Except as specified otherwise in this subsection, Load Zones established by NOIEs will be treated the same as other Load Zones, including a 36-month notice requirement for ERCOT Board approval of any changes to Load Zones; and

(g) Three years after a NOIE offers its Customers retail choice, the NOIE's Load must be merged into the appropriate Competitive Load Zone(s). For a Load Zone that is an aggregation of NOIE systems of which less than all of the NOIEs opt into Customer Choice, each remaining NOIE in that NOIE Load Zone may choose to have its Load merged into the appropriate Competitive Load Zone(s) under the same three-year time frame.

3.4.4 DC Tie Load Zones

A DC Tie Load Zone contains only the Electrical Bus in the ERCOT Transmission Grid that connects the DC Tie and is used in the settlement of the DC Tie Load in that zone.

3.4.5 Additional Load Buses

ERCOT shall assign new Electrical Buses to a Load Zone and Cost Allocation Zone in accordance with the following rules; changes are effective immediately:

(a) For each new Electrical Bus serving Load of a NOIE that is a part of a NOIE Load Zone, the new Electrical Bus will be assigned to that NOIE Load Zone;

(b) For each new Electrical Bus not covered in paragraph (a) above, connected via Transmission Facilities to Electrical Buses all located within the same Competitive Load Zone, the new Electrical Bus will be assigned to that Competitive Load Zone;

(c) For each new Electrical Bus not covered in paragraphs (a) or (b) above, ERCOT shall simulate LMPs for the annual peak hour of the system with the new Electrical Bus incorporated into the model. ERCOT shall assign that new Electrical Bus to the Competitive Load Zone with the closest matching zonal Settlement Point Price to the new Electrical Bus's LMP;

(d) For each new Electrical Bus covered in paragraph (a) above and connected via Transmission Facilities to Electrical Buses all located within the same Cost

Allocation Zone, then the new Electrical Bus will be assigned to that Cost Allocation Zone;

(e) For each new Electrical Bus covered in paragraph (a) above and not covered in paragraph (d) above, ERCOT shall simulate LMPs for the annual peak hour of the system with the new Electrical Bus incorporated into the model. ERCOT shall assign each new Electrical Bus associated with a NOIE that is a part of a NOIE Load Zone to the Cost Allocation Zone with the closest matching zonal Settlement Point Price to the new Electrical Bus's LMP.

(f) For each new Electrical Bus not covered in paragraph (a), the new Electrical Bus is assigned to the same Cost Allocation Zone as its designated Load Zone;

3.5 Hubs

3.5.1 Process for Defining Hubs

(1) Hubs settled through ERCOT may only be created by an amendment to Section 3.5.2, Hub Definitions. Hubs are made up of one or more Electrical Buses. ERCOT shall post the list of Electrical Buses (including their names) that are part of a Hub on the MIS Public Area. A Hub, once defined, may not be modified except as explicitly described in the definition of that Hub.

(2) When any Electrical Bus within a Hub Bus is removed from the Network Operations Model or the CRR Network Model through permanent changes to the Network Operations Model or CRR Network Model, ERCOT shall provide notice to all Market Participants on the MIS Public Area as soon as practicable and exclude that Electrical Bus from the Hub Bus price calculation.

(3) When any Electrical Bus within a Hub Bus is added to the Network Operations Model or the CRR Network Model through changes to the Network Operations Model or CRR Network Model, ERCOT shall provide notice to all Market Participants as soon as practicable and include that Electrical Bus in the Hub Bus price calculation.

(4) When any Electrical Bus within a Hub Bus is disconnected from the Network Operations Model or the CRR Network Model through operations changes in transmission topology temporarily, ERCOT shall provide notice to all Market Participants as soon as practicable and exclude that Electrical Bus from the Hub Bus price calculation.

(5) In the event of a permanent change that removes the Hub Bus from the ERCOT Transmission Grid, ERCOT shall file a Protocol Revision Request (PRR) to revise the appropriate Hub definition.

(6) If a TSP or ERCOT plans a nomenclature change in the Network Operations Model or the CRR Network Model, ERCOT shall file a PRR to include the nomenclature change in

the Hub Bus definitions before implementing the name change to either the Network Operations Model or the CRR Network Model.

3.5.2 Hub Definitions

3.5.2.1 North 345 kV Hub (North 345)

(1) The North 345 kV Hub is composed of the following Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	ANASW	345	NORTH
2	CN345	345	NORTH
3	WLSH	345	NORTH
4	FMRVL	345	NORTH
5	LPCCS	345	NORTH
6	MNSES	345	NORTH
7	PRSSW	345	NORTH
8	SSPSW	345	NORTH
9	VLSES	345	NORTH
10	ALNSW1	345	NORTH
11	ALNSW2	345	NORTH
12	ALLNC	345	NORTH
13	BNDVS	345	NORTH
14	BNBSW	345	NORTH
15	BBSES	345	NORTH
16	BOSQUESW	345	NORTH
17	CDHSW	345	NORTH
18	CNTRY1	345	NORTH
19	CNTRY3	345	NORTH
20	CRLNW	345	NORTH
21	CMNSW	345	NORTH
22	CNRSW	345	NORTH
23	CRTLD	345	NORTH
24	DCSES	345	NORTH
25	EMSES	345	NORTH
26	ELKTN	345	NORTH
27	ELMOT	345	NORTH
28	EVRSW	345	NORTH
29	KWASS	345	NORTH
30	FGRSW	345	NORTH
31	FORSW	345	NORTH
32	FRNYPP1	345	NORTH
33	FRNYPP2	345	NORTH
34	GIBCRK	345	NORTH
35	HKBRY	345	NORTH
36	VLYRN	345	NORTH
37	JEWETN	345	NORTH
38	JEWETS	345	NORTH

	ERCOT Operations		
No.	Hub Bus	kV	Hub
39	KNEDL	345	NORTH
40	KLNSW	345	NORTH
41	LCSES	345	NORTH
42	LIGSW	345	NORTH
43	LEG	345	NORTH
44	LFKSW	345	NORTH
45	LWSSW	345	NORTH
46	MLSES	345	NORTH
47	MCCREE	345	NORTH
48	MDANP1	345	NORTH
49	MDANP2	345	NORTH
50	ENTPR	345	NORTH
51	NCDSE	345	NORTH
52	NORSW	345	NORTH
53	NUCOR	345	NORTH
54	PKRSW	345	NORTH
55	KMCHI	345	NORTH
56	PTENN	345	NORTH
57	RENSW	345	NORTH
58	RCHBR1	345	NORTH
59	RCHBR2	345	NORTH
60	RNKSW	345	NORTH
61	RKCRK	345	NORTH
62	RYSSW	345	NORTH
63	SGVSW	345	NORTH
64	SHBSW	345	NORTH
65	SHRSW	345	NORTH
66	SHRTP	345	NORTH
67	SCSES	345	NORTH
68	SYCRK	345	NORTH
69	THSES	345	NORTH
70	TMPSW	345	NORTH
71	TNP_ONE	345	NORTH
72	TRCNR	345	NORTH
73	TRSES1	345	NORTH
74	TRSES2	345	NORTH
75	TOKSW	345	NORTH
76	VENSWN	345	NORTH
77	VENSWS	345	NORTH

No.	ERCOT Operations Hub Bus	kV	Hub
78	WLVEE	345	NORTH
79	W_DENT	345	NORTH
80	WTRML	345	NORTH
81	WCSWS	345	NORTH
82	WEBBS	345	NORTH
83	WHTNY	345	NORTH
84	WCPP	345	NORTH

(2) The North 345 kV Hub Price is the simple average of the Hub Bus prices for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{North345} = \sum_{hb} (\mathbf{HUBDF}_{hb, North345} * \mathbf{DAHBP}_{hb, North345}), \text{ if } \mathbf{HB}_{North345} \neq 0$$

$$\mathbf{DASPP}_{North345} = \mathbf{DASPP}_{ERCOT345Bus}, \text{ if } \mathbf{HB}_{North345} = 0$$

Where:

$$DAHBP_{hb, North345} = \sum_{b} (HBDF_{b, hb, North345} * DALMP_{b, hb, North345})$$

$$HUBDF_{hb, North345} = IF(HB_{North345}=0, 0, 1 / HB_{North345})$$

$$HBDF_{b, hb, North345} = IF(B_{hb, North345}=0, 0, 1 / B_{hb, North345})$$

The above variables are defined as follows:

Variable	Unit	Definition
$DASPP_{North345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
$DAHBP_{hb, North345}$	\$/MWh	*Day-Ahead Hub Bus Price at Hub Bus*—The DAM energy price at Hub Bus *hb* for the hour.
$DALMP_{b, hb, North345}$	\$/MWh	*Day-Ahead Locational Marginal Price at Electrical Bus of Hub Bus*—The DAM LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the hour.
$HUBDF_{hb, North345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, North345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.

Variable	Unit	Definition
$HB_{North345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{North345} = \sum_{hb} (\mathbf{HUBDF}_{hb,\, North345} * (\sum_{y} (\mathbf{RTHBP}_{hb,\, North345,\, y} * \mathbf{TLMP}_{y}) / (\sum_{y} \mathbf{TLMP}_{y}))), \textbf{ if } \mathbf{HB}_{North345} \neq 0$$

$$\mathbf{RTSPP}_{North345} = \mathbf{RTSPP}_{ERCOT345Bus}, \textbf{ if } \mathbf{HB}_{North345} = 0$$

Where:

$$RTHBP_{hb,\, North345,\, y} = \sum_{b} (HBDF_{b,\, hb,\, North345} * RTLMP_{b,\, hb,\, North345,\, y})$$

$$HUBDF_{hb,\, North345} = IF(HB_{North345}=0, 0, 1 / HB_{North345})$$

$$HBDF_{b,\, hb,\, North345} = IF(B_{hb,\, North345}=0, 0, 1 / B_{hb,\, North345})$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{North345}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$RTHBP_{hb,\, North345,\, y}$	$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$RTLMP_{b,\, hb,\, North345,\, y}$	$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
$HUBDF_{hb,\, North345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b,\, hb,\, North345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb,\, North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{North345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

3.5.2.2 South 345 kV Hub (South 345)

(1) The South 345 kV Hub is composed of the following Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	AUSTRO	345	SOUTH
2	BLESSING	345	SOUTH
3	CAGNON	345	SOUTH
4	COLETO	345	SOUTH
5	CLEASP	345	SOUTH
6	NEDIN	345	SOUTH
7	FAYETT	345	SOUTH
8	FPPYD	345	SOUTH
9	GARFIE	345	SOUTH
10	GUADG	345	SOUTH
11	HAYSEN	345	SOUTH
12	HILLCTRY	345	SOUTH
13	HOLMAN	345	SOUTH
14	KENDAL	345	SOUTH
15	LA_PALMA	345	SOUTH
16	LON_HILL	345	SOUTH
17	LOSTPI	345	SOUTH
18	LYTTON_S	345	SOUTH
19	MARION	345	SOUTH
20	PAWNEE	345	SOUTH
21	RIOHONDO	345	SOUTH
22	RIONOG	345	SOUTH
23	SALEM	345	SOUTH
24	SDSES	345	SOUTH
25	SANMIGL	345	SOUTH
26	SKYLINE	345	SOUTH
27	STP	345	SOUTH
28	CALAVERS	345	SOUTH
29	BRAUNIG	345	SOUTH
30	WHITEPT	345	SOUTH
31	ZORN	345	SOUTH

(2) The South 345 kV Hub Price is the simple average of the Hub Bus prices for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{South345} = \sum_{hb} (\mathbf{HUBDF}_{hb,\, South345} * \mathbf{DAHBP}_{hb,\, South345}) \text{ , if } \mathbf{HB}_{South345} \neq 0$$

$$\mathbf{DASPP}_{South345} = \mathbf{DASPP}_{ERCOT345Bus}\text{, if } \mathbf{HB}_{South345} = 0$$

Where:

$$\text{DAHBP}_{hb,\, South345} = \sum_{b} (\text{HBDF}_{b,\, hb,\, South345} * \text{DALMP}_{b,\, hb,\, South345})$$

$$\text{HUBDF}_{hb,\, South345} = \text{IF}(\text{HB}_{South345}=0,\ 0,\ 1 / \text{HB}_{South345})$$

$$\text{HBDF}_{b,\, hb,\, South345} = \text{IF}(\text{B}_{hb,\, South345}=0,\ 0,\ 1 / \text{B}_{hb,\, South345})$$

The above variables are defined as follows:

Variable	Unit	Definition
DASPP $_{South345}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
DAHBP $_{hb,\, South345}$	\$/MWh	*Day-Ahead Hub Bus Price at Hub Bus*—The DAM energy price at Hub Bus *hb* for the hour.
DALMP $_{b,\, hb,\, South345}$	\$/MWh	*Day-Ahead Locational Marginal Price at Electrical Bus of Hub Bus*—The DAM LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the hour.
HUBDF $_{hb,\, South345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b,\, hb,\, South345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
B $_{hb,\, South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB $_{South345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{South345} = \sum_{hb} (\mathbf{HUBDF}_{hb,\, South345} * (\sum_{y} (\mathbf{RTHBP}_{hb,\, South345,\, y} * \mathbf{TLMP}_{y}) / (\sum_{y} \mathbf{TLMP}_{y}))) \text{, if } \mathbf{HB}_{South345} \neq 0$$

$$\mathbf{RTSPP}_{South345} = \mathbf{RTSPP}_{ERCOT345Bus}\text{, if } \mathbf{HB}_{South345} = 0$$

Where:

$$\text{RTHBP}_{hb,\, South345,\, y} = \sum_{b} (\text{HBDF}_{b,\, hb,\, South345} * \text{RTLMP}_{b,\, hb,\, South345,\, y})$$

$$HUBDF_{hb,\ South345} = IF(HB_{South345}=0,\ 0,\ 1\ /\ HB_{South345})$$

$$HBDF_{b,\ hb,\ South345} = IF(B_{hb,\ South345}=0,\ 0,\ 1\ /\ B_{hb,\ South345})$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$RTSPP_{South345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$RTHBP_{hb,\ South345,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$RTLMP_{b,\ hb,\ South345,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
$HUBDF_{hb,\ South345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b,\ hb,\ South345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb,\ South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{South345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

3.5.2.3 Houston 345 kV Hub (Houston 345)

(1) The Houston 345 kV Hub is composed of the following listed Hub Buses:

	ERCOT Operations		
No.	Hub Bus	kV	Hub
1	ADK	345	HOUSTON
2	_BI	345	HOUSTON
3	CBY	345	HOUSTON
4	CTR	345	HOUSTON
5	CHB	345	HOUSTON
6	DPW	345	HOUSTON
7	DOW	345	HOUSTON
8	RNS	345	HOUSTON
9	GBY	345	HOUSTON
10	_JN	345	HOUSTON
11	_KG	345	HOUSTON

No.	ERCOT Operations Hub Bus	kV	Hub
12	KDL	345	HOUSTON
13	_NB	345	HOUSTON
14	_OB	345	HOUSTON
15	PHR	345	HOUSTON
16	SDN	345	HOUSTON
17	SMITHERS	345	HOUSTON
18	THW	345	HOUSTON
19	WAP	345	HOUSTON
20	_WO	345	HOUSTON

(2) The Houston 345 kV Hub Price is the simple average of the Hub Bus prices for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time-weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\,Houston345} = \sum_{hb} (\mathbf{HUBDF}_{\,hb,\,Houston345} * \mathbf{DAHBP}_{\,hb,\,Houston345}), \text{ if } \mathbf{HB}_{\,Houston345} \neq 0$$

$$\mathbf{DASPP}_{\,Houston345} = \mathbf{DASPP}_{ERCOT345Bus}, \text{ if } \mathbf{HB}_{\,Houston345} = 0$$

Where:

$$\text{DAHBP}_{\,hb,\,Houston345} = \sum_{b} (\text{HBDF}_{\,b,\,hb,\,Houston345} * \text{DALMP}_{\,b,\,hb,\,Houston345})$$

$$\text{HUBDF}_{\,hb,\,Houston345} = \text{IF}(\text{HB}_{\,Houston345}=0,\ 0,\ 1\ /\ \text{HB}_{\,Houston345})$$

$$\text{HBDF}_{\,b,\,hb,\,Houston345} = \text{IF}(\text{B}_{\,hb,\,Houston345}=0,\ 0,\ 1\ /\ \text{B}_{\,hb,\,Houston345})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{DASPP}_{\text{Houston345}}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
$\text{DAHBP}_{\text{hb, Houston345}}$	\$/MWh	*Day-Ahead Hub Bus Price at Hub Bus*—The DAM energy price at Hub Bus *hb* for the hour.
$\text{DALMP}_{\text{b, hb, Houston345}}$	\$/MWh	*Day-Ahead Locational Marginal Price at Electrical Bus of Hub Bus*—The DAM LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the hour.
$\text{HUBDF}_{\text{hb, Houston345}}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$\text{HBDF}_{\text{b, hb, Houston345}}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.

Variable	Unit	Definition
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{Houston345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{Houston345} = \sum_{hb} (\mathbf{HUBDF}_{hb, Houston345} * (\sum_{y} (\mathbf{RTHBP}_{hb, Houston345, y} * \mathbf{TLMP}_{y}) / (\sum_{y} \mathbf{TLMP}_{y}))), \text{ if } \mathbf{HB}_{Houston345} \neq 0$$

$$\mathbf{RTSPP}_{Houston345} = \mathbf{RTSPP}_{ERCOT345Bus}, \text{ if } \mathbf{HB}_{Houston345} = 0$$

Where:

$$RTHBP_{hb, Houston345, y} = \sum_{b} (HBDF_{b, hb, Houston345} * RTLMP_{b, hb, Houston345, y})$$

$$HUBDF_{hb, Houston345} = IF(HB_{Houston345}=0, 0, 1 / HB_{Houston345})$$

$$HBDF_{b, hb, Houston345} = IF(B_{hb, Houston345}=0, 0, 1 / B_{hb, Houston345})$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{Houston345}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$RTHBP_{hb, Houston345, y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$RTLMP_{b, hb, Houston345, y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
$HUBDF_{hb, Houston345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, Houston345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$HB_{Houston345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

3.5.2.4 West 345 kV Hub (West 345)

(1) The West 345 kV Hub is composed of the following listed Hub Buses:

No.	ERCOT Operations Hub Bus	kV	Hub
1	ABMB	345	WEST
2	BOMSW	345	WEST
3	OECCS	345	WEST
4	BTRCK	345	WEST
5	FSHSW	345	WEST
6	FLCNS	345	WEST
7	GRSES	345	WEST
8	JCKSW	345	WEST
9	MDLNE	345	WEST
10	MOSSW	345	WEST
11	MGSES	345	WEST
12	DCTM	345	WEST
13	ODEHV	345	WEST
14	OKLA	345	WEST
15	SARC	345	WEST
16	SWCOG	345	WEST
17	TWINBUTE	345	WEST

(2) The West 345 kV Hub Price is the simple average of the Hub Bus prices for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\ West345} = \sum_{hb} \mathbf{(HUBDF}_{\ hb,\ West345} \mathbf{\ *\ DAHBP}_{\ hb,\ West345}\mathbf{),\ if\ HB}_{\ West345} \mathbf{\neq 0}$$

$$\mathbf{DASPP}_{\ West345} = \mathbf{DASPP}_{ERCOT345Bus}\mathbf{,\ if\ HB}_{\ West345}\mathbf{=0}$$

Where:

$$\text{DAHBP}_{\ hb,\ West345} = \sum_{b} (\text{HBDF}_{\ b,\ hb,\ West345} * \text{DALMP}_{\ b,\ hb,\ West345})$$

$$\text{HUBDF}_{\ hb,\ West345} = \text{IF(HB}_{\ West345}\text{=0, 0, 1 / HB}_{\ West345}\text{)}$$

$$\text{HBDF}_{\,b,\,hb,\,West345} \quad = \quad \text{IF}(\text{B}_{\,hb,\,West345}=0,\ 0,\ 1\ /\ \text{B}_{\,hb,\,West345})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DASPP}_{\text{West345}}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
$\text{DAHBP}_{\text{hb, West345}}$	\$/MWh	*Day-Ahead Hub Bus Price at Hub Bus*—The DAM energy price at Hub Bus *hb* for the hour.
$\text{DALMP}_{\text{b, hb, West345}}$	\$/MWh	*Day-Ahead Locational Marginal Price at Electrical Bus of Hub Bus*—The DAM LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the hour.
$\text{HUBDF}_{\text{hb, West345}}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$\text{HBDF}_{\text{b, hb, West345}}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$\text{B}_{\text{hb, West345}}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
$\text{HB}_{\text{West345}}$	none	The total number of Hub Buses in the Hub.

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,West345} \quad = \quad \sum_{hb} (\mathbf{HUBDF}_{\,hb,\,West345} * (\sum_{y} (\mathbf{RTHBP}_{\,hb,\,West345,\,y} * \mathbf{TLMP}_{\,y}) \ / \ (\sum_{y} \mathbf{TLMP}_{\,y}))), \text{ if } \mathbf{HB}_{\,West345} \neq 0$$

$$\mathbf{RTSPP}_{\,West345} \quad = \quad \mathbf{RTSPP}_{ERCOT345Bus}, \text{ if } \mathbf{HB}_{\,West345} = 0$$

Where:

$$\text{RTHBP}_{\,hb,\,West345,\,y} \quad = \quad \sum_{b} (\text{HBDF}_{\,b,\,hb,\,West345} * \text{RTLMP}_{\,\text{b, hb, West345, y}})$$

$$\text{HUBDF}_{\,hb,\,West345} \quad = \quad \text{IF}(\text{HB}_{\,West345}=0,\ 0,\ 1\ /\ \text{HB}_{\,West345})$$

$$\text{HBDF}_{\,b,\,hb,\,West345} \quad = \quad \text{IF}(\text{B}_{\,hb,\,West345}=0,\ 0,\ 1\ /\ \text{B}_{\,hb,\,West345})$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTSPP}_{\text{West345}}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$\text{RTHBP}_{\text{hb, West345, y}}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$\text{RTLMP}_{\text{b, hb, West345, y}}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.

Variable	Unit	Description
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
HUBDF $_{hb,\ West345}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
HBDF $_{b,\ hb,\ West345}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
B $_{hb,\ West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb*.
hb	none	A Hub Bus that is a component of the Hub.
HB $_{West345}$	none	The total number of Hub Buses in the Hub with at least one energized component in each Hub Bus.

3.5.2.5 ERCOT Hub Average 345 kV Hub (ERCOT 345)

(1) The ERCOT Hub Average 345 kV Hub price, for both Day-Ahead and Real-Time, is the simple average of four prices from the applicable time period: the North 345 kV Hub price, the South 345 kV Hub price, the Houston 345 kV Hub price, and the West 345 kV Hub price.

(2) The Day-Ahead Settlement Point Price for the Hub "ERCOT 345" for a given Operating Hour is calculated as follows:

$$\textbf{DASPP}_{\ ERCOT345} = (\textbf{DASPP}_{\ North345} + \textbf{DASPP}_{\ South345} + \textbf{DASPP}_{\ Houston345} + \textbf{DASPP}_{\ West345}) \ / \ 4$$

The above variables are defined as follows:

Variable	Unit	Definition
DASPP $_{ERCOT345}$	\$/MWh	*Day-Ahead Settlement Point Price at ERCOT 345*—The DAM Settlement Point Price at ERCOT 345 Hub for the hour.
DASPP $_{North345}$	\$/MWh	*Day-Ahead Settlement Point Price at North 345*—The DAM Settlement Point Price at the North 345 Hub for the hour.
DASPP $_{South345}$	\$/MWh	*Day-Ahead Settlement Point Price at South 345*—The DAM Settlement Point Price at the South 345 Hub for the hour.
DASPP $_{Houston345}$	\$/MWh	*Day-Ahead Settlement Point Price at Houston 345*—The DAM Settlement Point Price at the Houston 345 Hub for the hour.
DASPP $_{West345}$	\$/MWh	*Day-Ahead Settlement Point Price at West 345*—The DAM Settlement Point Price at the West 345 Hub for the hour.

(3) The Real-Time Settlement Point Price for the Hub "ERCOT 345" for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{\,ERCOT345} = (\mathbf{RTSPP}_{\,North345} + \mathbf{RTSPP}_{\,South345} + \mathbf{RTSPP}_{\,Houston345} + \mathbf{RTSPP}_{\,West345}) / 4$$

The above variables are defined as follows:

Variable	Unit	Definition
$RTSPP_{ERCOT345}$	$/MWh	*Real-Time Settlement Point Price at ERCOT 345*—The *Real-Time* Settlement Point Price at ERCOT 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{North345}$	$/MWh	*Real-Time Settlement Point Price at North 345*—The Real-Time Settlement Point Price at the North 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{South345}$	$/MWh	*Real-Time Settlement Point Price at South 345*—The Real-Time Settlement Point Price at the South 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{Houston345}$	$/MWh	*Real-Time Settlement Point Price at Houston 345*—The Real-Time Settlement Point Price at the Houston 345 Hub for the 15-minute Settlement Interval.
$RTSPP_{West345}$	$/MWh	*Real-Time Settlement Point Price at West 345*—The Real-Time Settlement Point Price at the West 345 Hub for the 15-minute Settlement Interval.

3.5.2.6 ERCOT Bus Average 345 kV Hub (ERCOT 345 Bus)

(1) The ERCOT Bus Average 345 kV Hub is composed of the Hub Buses listed in Section 3.5.2.1, North 345 kV Hub (North 345); Section 3.5.2.2, South 345 kV Hub (South 345); Section 3.5.2.3, Houston 345 kV Hub (Houston 345); and Section 3.5.2.4,West 345 kV Hub (West 345).

(2) The ERCOT Bus Average 345 kV Hub is the simple average of the Hub Bus prices for each hour of the Settlement Interval of the DAM in the Day-Ahead and is the simple average of the time weighted Hub Bus prices for each 15-minute Settlement Interval in Real-Time, for each Hub Bus included in this Hub.

(3) The Day-Ahead Settlement Point Price of the Hub for a given Operating Hour is calculated as follows:

$$\mathbf{DASPP}_{\,ERCOT345Bus} = \sum_{hb} (\mathbf{HUBDF}_{\,hb,\,ERCOT345Bus} * \mathbf{DAHBP}_{\,hb,\,ERCOT345Bus}),\ \textbf{if HB}_{\,ERCOT345Bus} \neq \mathbf{0}$$

$$\mathbf{DASPP}_{\,ERCOT345Bus} = \mathbf{0},\ \textbf{if HB}_{\,ERCOT345Bus} = \mathbf{0}$$

Where:

$$DAHBP_{\,hb,\,ERCOT345Bus} = \sum_{b} (HBDF_{\,b,\,hb,\,ERCOT345Bus} * DALMP_{\,b,\,hb,\,ERCOT345Bus})$$

$$HUBDF_{\,hb,\,ERCOT345Bus} = 1 / (HB_{\,North345} + HB_{\,South345} + HB_{\,Houston345} + HB_{\,West345})$$

If Electrical Bus *b* is a component of “North 345”

$$HBDF_{\,b,\,hb,\,ERCOT345Bus} = IF(B_{\,hb,\,North345}=0, 0, 1 / B_{\,hb,\,North345})$$

Otherwise

If Electrical Bus *b* is a component of "South 345"

$HBDF_{b, hb, ERCOT345Bus}$ = IF($B_{hb, South345}$=0, 0, 1 / $B_{hb, South345}$)

Otherwise

If Electrical Bus *b* is a component of "Houston 345"

$HBDF_{b, hb, ERCOT345Bus}$ = IF($B_{hb, Houston345}$=0, 0, 1 / $B_{hb, Houston345}$)

Otherwise

$HBDF_{b, hb, ERCOT345Bus}$ = IF($B_{hb, West345}$=0, 0, 1 / $B_{hb, West345}$)

The above variables are defined as follows:

Variable	Unit	Definition
$DASPP_{ERCOT345Bus}$	\$/MWh	*Day-Ahead Settlement Point Price*—The DAM Settlement Point Price at the Hub, for the hour.
$DAHBP_{hb, ERCOT345Bus}$	\$/MWh	*Day-Ahead Hub Bus Price at Hub Bus*—The DAM energy price at Hub Bus *hb* for the hour.
$DALMP_{b, hb, ERCOT345Bus}$	\$/MWh	*Day-Ahead Locational Marginal Price at Electrical Bus of Hub Bus*—The DAM LMP at Electrical Bus *b* that is a component of Hub Bus *hb* for the hour.
$HUBDF_{hb, ERCOT345Bus}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b, hb, ERCOT345Bus}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb, North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "North 345".
$B_{hb, South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "South 345".
$B_{hb, Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "Houston 345".
$B_{hb, West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "West 345".
hb	none	A Hub Bus that is a component of the Hub.
$HB_{North345}$	none	The total number of Hub Buses in "North 345".
$HB_{South345}$	none	The total number of Hub Buses in "South 345".
$HB_{Houston345}$	none	The total number of Hub Buses in "Houston 345".
$HB_{West345}$	none	The total number of Hub Buses in "West 345".

(4) The Real-Time Settlement Point Price of the Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP}_{ERCOT345Bus} = \sum_{hb} (\mathbf{HUBDF}_{hb, ERCOT345Bus} * (\sum_{y} (\mathbf{RTHBP}_{hb, ERCOT345Bus, y} * \mathbf{TLMP}_{y}) / (\sum_{y} \mathbf{TLMP}_{y}))), \textbf{ if } \mathbf{HB}_{ERCOT345Bus} \neq 0$$

$$\mathbf{RTSPP}_{ERCOT345Bus} = 0, \textbf{ if } \mathbf{HB}_{ERCOT345Bus} = 0$$

Where:

$$RTHBP_{hb,\ ERCOT345Bus,\ y} = \sum_{b} (HBDF_{b,\ hb,\ ERCOT345Bus} * RTLMP_{b,\ hb,\ ERCOT345Bus,\ y})$$

$$HUBDF_{hb,\ ERCOT345Bus} = 1 / (HB_{North345} + HB_{South345} + HB_{Houston345} + HB_{West345})$$

If Electrical Bus *b* is a component of "North 345"

$$HBDF_{b,\ hb,\ ERCOT345Bus} = IF(B_{hb,\ North345}=0,\ 0,\ 1 / B_{hb,\ North345})$$

Otherwise

If Electrical Bus *b* is a component of "South 345"

$$HBDF_{b,\ hb,\ ERCOT345Bus} = IF(B_{hb,\ South345}=0,\ 0,\ 1 / B_{hb,\ South345})$$

Otherwise

If Electrical Bus *b* is a component of "Houston 345"

$$HBDF_{b,\ hb,\ ERCOT345Bus} = IF(B_{hb,\ Houston345}=0,\ 0,\ 1 / B_{hb,\ Houston345})$$

Otherwise

$$HBDF_{b,\ hb,\ ERCOT345Bus} = IF(B_{hb,\ West345}=0,\ 0,\ 1 / B_{hb,\ West345})$$

The above variables are defined as follows:

Variable	Unit	Description
$RTSPP_{ERCOT345Bus}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Hub, for the 15-minute Settlement Interval.
$RTHBP_{hb,\ ERCOT345Bus,\ y}$	\$/MWh	*Real-Time Hub Bus Price at Hub Bus per SCED interval*—The Real-Time energy price at Hub Bus *hb* for the SCED interval *y*.
$RTLMP_{b,\ hb,\ ERCOT345Bus,\ y}$	\$/MWh	*Real-Time Locational Marginal Price at Electrical Bus of Hub Bus per interval*—The Real-Time LMP at Electrical Bus *b* that is a component of Hub Bus *hb*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval
$HUBDF_{hb,\ ERCOT345Bus}$	none	*Hub Distribution Factor per Hub Bus*—The distribution factor of Hub Bus *hb*.
$HBDF_{b,\ hb,\ ERCOT345Bus}$	none	*Hub Bus Distribution Factor per Electrical Bus of Hub Bus*—The distribution factor of Electrical Bus *b* that is a component of Hub Bus *hb*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An energized Electrical Bus that is a component of a Hub Bus.
$B_{hb,\ North345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "North 345".
$B_{hb,\ South345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "South 345".
$B_{hb,\ Houston345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "Houston 345".
$B_{hb,\ West345}$	none	The total number of energized Electrical Buses in Hub Bus *hb* that is a component of "West 345".
hb	none	A Hub Bus that is a component of the Hub.
$HB_{North345}$	none	The total number of Hub Buses in "North 345".

Variable	Unit	Description
$HB_{South345}$	none	The total number of Hub Buses in “South 345”.
$HB_{Houston345}$	none	The total number of Hub Buses in “Houston 345”.
$HB_{West345}$	none	The total number of Hub Buses in “West 345”.

3.5.3 ERCOT Responsibilities for Managing Hubs

3.5.3.1 Posting of Hub Buses and Electrical Buses included in Hubs

ERCOT shall post a list of all the Hub Buses included in each Hub on the MIS Public area. The list must include the name and kV rating for each Electrical Bus included in each Hub Bus.

3.5.3.2 Calculation of Hub Prices

ERCOT shall calculate Hub prices for each Settlement Interval as identified in the description of each Hub.

3.6 Load Participation

(1) Load Resources may participate by providing the following types of service:

(a) Ancillary Service:

(i) Regulation Up Reserve Service (Reg-Up);

(ii) Regulation Down Reserve Service (Reg-Down);

(iii) Responsive Reserve Service (RRS);

(iv) Non-Spinning Reserve Service (Non-Spin); and

(b) Voluntary load response in Real-Time.

(2) Except for voluntary load response, loads participating in any ERCOT market must be individually registered as a Load Resource by ESID and are subject to qualification testing administered by ERCOT. All ERCOT settlements resulting from Load Resource participation are made only with the QSE representing the Load Resource.

3.7 Resource Parameters

(1) A Resource Entity shall register Resource Parameters for its Resources with ERCOT.

(2) ERCOT shall provide each Qualified Scheduling Entity (QSE) that represents a Resource the ability to submit changes to Resource Parameters for that Resource.

(3) The QSE may revise Resource Parameters only with sufficient documentation to justify a change in Resource Parameters.

(4) ERCOT shall use the Resource Parameters as inputs into the Day-Ahead Market (DAM), Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), Resource Limit Calculator, Load Frequency Control (LFC), and other ERCOT business processes.

(5) The Independent Market Monitor (IMM) may require the QSE to provide justification for the Resource Parameters submitted.

(6) Seasons for seasonal parameters are defined in the Operating Guides.

3.7.1 Resource Parameter Criteria

3.7.1.1 Generation Resource Parameters

(1) General Resource Parameters submitted by a Resource Entity must include the following for each of its Generation Resources:

(a) The Resource's name;

(b) High reasonability limit used to verify operator entries of High Sustained Limit (HSL);

(c) Low reasonability limit used to verify operator entries of Low Sustained Limit (LSL);

(d) Type of Resource – steam turbine, hydro, gas turbine, combined cycle, other;

(e) Qualifying Facility (QF) status, if applicable;

(f) Normal Ramp Rate curve;

(g) Emergency Ramp Rate curve;

(h) Minimum On-Line time – The minimum number of consecutive hours the Resource must be On-Line before being shut down;

(i) Minimum Off-Line time – The minimum number of consecutive hours the Resource must be Off-Line before being restarted;

(j) Hot start time – The time, in hours, from the ERCOT notice to the Resource breaker-closing, for a Resource in its hot-temperature state;

(k) Intermediate start time – The time interval, in hours, from the ERCOT notice to the Resource breaker-closing, for a Resource in its intermediate temperature state; and

(l) Cold start time – The time interval, in hours, from the ERCOT notice to the Resource breaker-closing, for a Resource in its cold-temperature state.

(2) Seasonal Resource Parameters must be submitted by a Resource Entity and must include the following for each of its Generation Resources:

(a) Seasonal gross and net MW rating;

(b) Conversion constants to be used to convert from gross MW to net MW or net MW to gross MW in accordance with ERCOT Operating Guides, if applicable;

(c) Maximum weekly starts – The maximum number of times a Resource can be started in seven consecutive days under normal operating conditions;

(d) Maximum On-Line time – The maximum number of consecutive hours a Resource can run before it needs to be shut down;

(e) Maximum daily starts – The maximum number of times a Resource can be started in a 24 hour period under normal operating conditions;

(f) Maximum weekly energy – The maximum amount of energy, in MWh, a Resource can produce in seven consecutive days;

(g) Hot-to-intermediate time – The time, in hours, after shutdown that a hot-temperature-state Resource takes to cool down to intermediate-temperature state; and

(h) Intermediate-to-cold time – The time, in hours, after shutdown that an intermediate-temperature-state Resource takes to cool down to cold-temperature state.

3.7.1.2 Load Resource Parameters

(1) Resource Parameters submitted by a Resource Entity must include the following for each of its Load Resources that is not a Controllable Load Resource:

(a) The Resource's name;

(b) High reasonability limit used to verify operator entries for the Low Power Consumption (LPC);

(c) Low reasonability limit used to verify operator entries for the Maximum Power Consumption (MPC);

(d) Minimum interruption time – The minimum number of consecutive hours the Resource can be deployed (between breaker open to breaker close);

(e) Minimum restoration time – The minimum number of consecutive hours the Resource must remain energized (not deployed), from the time the Resource is restored from interruption and available for the next potential interruption;

(f) Maximum weekly deployments – The maximum number of times the Resource can be deployed in seven consecutive days under normal operating conditions;

(g) Maximum interruption time – The maximum number of consecutive hours the Resource can remain deployed before it needs to be energized;

(h) Maximum daily deployments – The maximum number of times the Resource can be deployed in a day under normal operating conditions;

(i) Maximum weekly energy – The maximum amount of energy, in MWh, a for which the Resource can be deployed in seven consecutive days; and

(j) Minimum notice time – The notice time that the Resource requires before deployment (e.g., instantaneous, 30 minutes, etc.).

(2) Resource Parameters submitted by a Resource Entity must include the following for each of its Controllable Load Resources:

(a) The Resource's name;

(b) High reasonability limit used to verify operator entries for the LPC;

(c) Low reasonability limit used to verify operator entries for the MPC;

(d) Normal Ramp Rate curve;

(e) Emergency Ramp Rate curve;

(f) Maximum deployment time – The maximum amount of time a Controllable Load Resource can be deployed before it must return to normal operating conditions; and

(g) Maximum weekly energy – The maximum amount of energy a Controllable Load Resource can be deployed in seven consecutive days.

3.7.1.3 Changes in Resource Parameters with Operational Impacts

The QSE representing each Resource shall have the responsibility to submit changes to Resource Parameters for those Resource Parameters related to the Current Operating Plan (COP), as described in Section 3.9, Current Operating Plan (COP), and to Real-Time operations as described in Section 6, Adjustment Period and Real-Time Operations.

3.7.2 Resource Parameter Validation

ERCOT shall verify that changes to Resource Parameters submitted by a Resource Entity or the QSE representing the Resource comply with the applicable criteria in Section 3.7.1, Resource Parameter Criteria. If a Resource Parameter is determined to be invalid, then ERCOT shall reject it and provide written notice to the Resource Entity or the QSE representing the Resource, as appropriate, of the reason for the rejection.

3.8 Special Considerations for Split Generation Meters

(1) When a generation meter is split, as provided for in Section 10.3.2.1, Generation Meter Splitting, two or more independent Generation Resources must be created in the ERCOT Network Operations Model according to Section 3.10.7.2, Modeling of Resources and Transmission Loads, to function in all respects as individual "Split Generation Resources" in ERCOT System operation.

(2) Each QSE representing an individual Split Generation Resource shall collect and shall submit to ERCOT the Resource Parameters defined under Section 3.7, Resource Parameters, for the individual Split Generation Resource it represents. The parameters provided must be consistent with the parameters submitted by each other QSE that represents a Split Generation Resource from the same generation facility. The parameters submitted for the individual Split Generation Resource for limits and ramp rates must be according to the capability of the individual Split Generation Resource represented by each QSE. Startup and shutdown times, time to change status and number of starts must be identical for all the individual Split Generation Resources submitted by each QSE. ERCOT shall review data submitted by each QSE representing Split Generation Resources for consistency and notify each QSE of any errors.

(3) Each Split Generation Resource may be represented by a different QSE. A Split Generation Resource must comply in all respects to the requirements of a Generation Resource specified under these Protocols.

(4) Each QSE is responsible for representing its individual Split Generation Resource in its COP.

(5) If an individual Split Generation Resource is On-Line, then all individual Split Generation Resources for that generation facility are considered On-Line. Each QSE representing a Split Generation Resource shall update its individual Resource Status appropriately.

(6) Each QSE representing an individual Split Generation Resource may independently submit Energy Offer Curves and Three Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all individual Split Generation Resources in a generation facility must be committed or decommitted together.

(7) Each QSE submitting verifiable cost data to ERCOT shall coordinate among all owners of a generation facility to provide individual Split Generation Resource data consistent

with the total verifiable cost of the entire generation facility. ERCOT may compare the total verifiable costs with other similarly situated Generation Resources to determine the reasonability of the cost.

3.9 Current Operating Plan (COP)

(1) Each QSE that represents a Resource must submit a COP under this Section.

(2) ERCOT shall use the information provided in the COP to calculate the High Ancillary Service Limit (HASL) and Low Ancillary Service Limit (LASL) for each Resource for the RUC processes.

(3) ERCOT shall monitor the accuracy of each QSE's COP as outlined in Section 8, Performance Monitoring and Compliance.

(4) A QSE must notify ERCOT that it plans to have a Resource On-Line by means of the COP using the Resource Status codes listed in Section 3.9.1, Current Operating Plan (COP) Criteria, paragraph (4)(b)(i). The QSE must show the Resource as On-Line with a Status of "ONRUC," indicating a RUC process committed the Resource for all RUC-Committed Intervals. A QSE may not use a Resource during that Resource's RUC-Committed Interval to meet the QSE's Ancillary Service Supply Responsibility.

(5) To reflect changes to a Resource's capability, each QSE shall report by exception, changes to the COP for all hours after the Operating Period through the rest of the Operating Day.

(6) When a QSE updates its COP to show changes in Resource status, the QSE shall update for each On-Line Resource, either an Energy Offer Curve under Section 4.4.9, Energy Offers and Bids, or Output Schedule under Section 6.4.2, Output Schedules.

(7) Each QSE, including QSEs representing RMR Units, or Black Start Resources, shall submit a revised COP reflecting changes in Resource availability as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change.

(8) Each QSE representing a Qualifying Facility must submit an LSL that represents the minimum energy available, in MW, from the unit for economic dispatch based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

3.9.1 Current Operating Plan (COP) Criteria

(1) Each QSE that represents a Resource must submit a COP to ERCOT that reflects expected operating conditions for each Resource for each hour in the next seven Operating Days.

(2) Each QSE that represents a Resource shall update its COP reflecting changes in availability of any Resource as soon as reasonably practicable, but in no event later than 60 minutes after the event that caused the change.

(3) The Resource capacity in a QSE's COP must be sufficient to supply the Ancillary Service Supply Responsibility of that QSE.

(4) A COP must include the following for each Resource represented by the QSE:

(a) The name of the Resource;

(b) The expected Resource Status:

(i) Select one of the following for Generation Resources synchronized to the ERCOT System that best describes the Resource's status:

(A) ONRUC – On-Line and the hour is a RUC-Committed Interval;

(B) ONREG – On-Line Resource with Energy Offer Curve providing Regulation Service;

(C) ON – On-Line Resource with Energy Offer Curve;

(D) ONDSR – On-Line Dynamically Scheduled Resource;

(E) ONOS – On-Line Resource with Output Schedule;

(F) ONOSREG – On-Line Resource with Output Schedule providing Regulation Service;

(G) ONDSRREG – On-Line Dynamically Scheduled Resource providing Regulation Service;

(H) ONTEST – On-Line Test with Output Schedule;

(I) ONEMR – On-Line EMR (available for commitment or dispatch only for ERCOT-declared Emergency Conditions; the QSE may appropriately set LSL and HSL to reflect operating limits); and

(J) ONRR – On-Line as a synchronous condenser (hydro) providing Responsive Reserve but unavailable for dispatch by SCED and available for commitment by RUC.

(ii) Select one of the following for Off-Line Generation Resources not synchronized to the ERCOT System that best describes the Resource status:

(A) OUT – Off-Line and unavailable;

(B) OFFNS – Off -Line but reserved for Non-Spin;

(C) OFF – Off-Line but available for commitment by DAM and RUC; and

(D) EMR – Available for commitment only for ERCOT-declared Emergency Condition events; the QSE may appropriately set LSL and HSL to reflect operating limits; and

(iii) Select one of the following for Load Resources:

(A) ONRGL – Available for dispatch of Regulation Service;

(B) ONRRCLR – Available for dispatch of Responsive Reserve Service as a Controllable Load Resource;

(C) ONRL – Available for dispatch of Responsive Reserve Service or Non-Spin, excluding Controllable Load Resources; and

(D) OUTL – Not available;

(c) The High Sustained Limit (HSL);

(d) The Low Sustained Limit (LSL);

(e) The High Emergency Limit (HEL);

(f) The Low Emergency Limit (LEL); and

(g) Ancillary Service Resource Responsibility capacity in MW for:

(i) Reg-Up;

(ii) Reg-Down;

(iii) Responsive Reserve Service; and

(iv) Non-Spin

(5) For combined-cycle Resources, the above items are required for each operating configuration.

(6) ERCOT may accept COPs only from QSEs.

(7) A QSE representing a Wind-Powered Generation Resource (WGR) must enter an HSL value that is less than or equal to the amount for that Resource from the most recent Wind-Powered Generation Resource Production Potential provided by ERCOT.

(8) A QSE representing a Resource that has a Resource Status of ONTEST must self-commit the Resource and must submit an Output Schedule for the Resource.

3.9.2 Current Operating Plan Validation

(1) ERCOT shall verify that each COP, on its submission, complies with the criteria described in Section 3.9.1, Current Operating Plan (COP) Criteria. ERCOT shall notify the QSE by means of the Messaging System if the QSE's COP is rejected or considered invalid for any reason. The QSE must then resubmit the COP within the appropriate market timeline.

(2) ERCOT must reject a COP that does not meet the criteria described in Section 3.9.1, Current Operating Plan (COP) Criteria.

(3) If a Resource is designated in the COP to provide Ancillary Service, then ERCOT shall verify that the COP complies with Section 3.16, Standards for Determining Ancillary Service Quantities. The Ancillary Service Supply Responsibilities as indicated in the Ancillary Service Resource Responsibility submitted immediately before the end of the Adjustment Period are physically binding commitments for each QSE for the corresponding Operating Period.

(4) ERCOT shall notify the QSE if the sum of the Ancillary Service capacity designated in the COP for each hour, by service type) is less than the QSE's Ancillary Service Supply Responsibility for each service type for that hour. If the QSE does not correct the deficiency within one hour after receiving the notice from ERCOT, then ERCOT shall follow the procedures outlined in Section 6.4.8.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency.

(5) A QSE may change Ancillary Service Resource designations by changing its COP, subject to Section 6.4.8.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency.

(6) If ERCOT determines that it needs more Ancillary Service during the Adjustment Period, then the QSE's allocated portion of the additional Ancillary Service may be Self-Arranged.

(7) ERCOT systems must be able to detect a change in status of a Resource shown in the COP and must provide notice to ERCOT operators of changes that a QSE makes to its COP.

(8) A QSE representing a Resource that has an Energy Offer Curve valid for an hour of the COP, may not designate a Resource Status of ONTEST, ONOS or ONDSR for that hour for that Resource.

3.10 Network Operations Modeling and Telemetry

(1) ERCOT shall use the physical characteristics, ratings, and operational limits of all Transmission Elements of the ERCOT Transmission Grid and other information from the Transmission Service Providers (TSPs) to specify limits within which the transmission network is defined in the network models made available to Market Participants on the Market Information System (MIS) Secure Area and used to operate the ERCOT Transmission Grid as updated.

(2) Because the ERCOT market requires accurate modeling of Transmission Elements in order to send reasonably accurate Base Points and pricing signals to Market Participants, ERCOT shall manage the Network Operations Model. By providing Base Points and pricing signals by Electrical Bus to Market Participants, the Market Participants' responses result in power flows on all Transmission Elements that ERCOT must monitor and, if necessary for reliability reasons, manage within ratings provided by the TSP and limits assigned by ERCOT including Generic Transmission Limits (GTLs) as may be defined in Section 3.10.7.6, Modeling of Generic Transmission Limits.

(3) TSPs shall provide ERCOT with equipment ratings and update the ratings as required by ERCOT. ERCOT shall post all equipment ratings on the MIS Secure Area no later than the day prior to the ratings becoming effective including the identity of the Transmission Element, old rating and new rating, effective date, and a text reason supplied by the appropriate TSP(s) for the rating change. ERCOT may request TSPs to provide detailed information on the methodology, including data for determination of each requested rating. ERCOT may review and comment on the methodology. ERCOT shall post all methodologies on the MIS Secure Area within seven days following a change in methodology.

(4) ERCOT must use system ratings consistent with the ratings expected to be used during Real-Time for the system condition being modeled, including Dynamic Ratings using expected temperatures for those system conditions. For each model, ERCOT shall post ratings and the ambient temperatures used to calculate the ratings on the MIS Secure Area when the model is published.

(5) ERCOT shall use consistent information within and between the various models used by ERCOT Operations, ERCOT Planning, and other workgroups in a manner that yields consistent results. For operational and planning models that are intended to represent the same system state the results should be consistent and the naming should be identical. An independent audit must be performed at least annually to confirm that consistent information is used in all ERCOT Operations models.

(6) ERCOT shall use a Network Operations Model Change Request (NOMCR) process to control all information entering the Network Operations Model. In order to allow for construction schedules, each NOMCR must be packaged as a single package describing any incremental changes and referencing any prerequisite NOMCRs, using an industry standard data exchange format. A package must contain a series of instructions that define the changes that need to be made to implement a network model modification.

ERCOT shall verify each package for completeness and accuracy prior to the period it is to be implemented.

(7) ERCOT shall use an automated process to manage the Common Information Model (CIM) compliant packages loaded into the Network Operations Model as each construction phase is completed. ERCOT shall reject any NOMCRs that are not CIM compliant. Each CIM compliant NOMCR must also be associated with commands to update the graphical displays associated with the network model modification. During the testing phase, each NOMCR must be tested for proper sequencing and its effects on downstream applications.

(8) ERCOT shall track each request received from TSPs and Resources via the NOMCR process, through implementation and final testing of the change. ERCOT shall notify each NOMCR requestor when the requested change is processed and implemented in accordance with Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall also provide the submitting TSP a link to a network model containing the change for verifying the implementation of the NOMCR and associated one-line displays. ERCOT shall post all NOMCRs on the MIS Secure Area within five Business Days following receipt of the NOMCR, consistent with CEII standards. When posting a NOMCR, each change must be posted using the CIM data exchange format showing incremental changes to the last posted ERCOT Network Operations Model, to facilitate TSPs and other Market Participants in updating their internal network models to reflect changes made at ERCOT. For each NOMCR, ERCOT shall post on the MIS Secure Area current status on the in-service date, including any prerequisite NOMCRs provided by the requestor.

(9) ERCOT shall update the Network Operations Model under this Section and coordinate it with the Planning Models for consistency to the extent applicable.

(10) Any requestor of an NOMCR must receive approval from ERCOT of an NOMCR before connecting of any associated equipment to the ERCOT Transmission Grid. ERCOT shall notify a requestor of any deficiencies in its NOMCR. ERCOT shall accept corrections to the NOMCR if the requestor has corrected any deficiencies by the required submittal date. ERCOT shall post any changes to an NOMCR on the MIS Secure Area within three Business Days of accepting corrections.

(11) On receipt of the information set forth in Section 3.10.7, ERCOT System Modeling Requirements, ERCOT shall review the information and notify the requestor of any required modifications. ERCOT may, at its discretion, require changes or more details regarding the work plan for the NOMCR. The requestor shall notify ERCOT and any other affected Entities as soon as practicable of any requested changes to the work plan defined in the NOMCR. The requestor shall consult with other Entities likely to be affected and shall revise the work plan, following any necessary or appropriate discussions with ERCOT and other affected Entities. ERCOT shall approve or reject the request, including any revisions made by the requestor, within 15 days of receipt of the complete request and any revisions. Following ERCOT approval, ERCOT shall publish a summary of the NOMCR on the MIS Secure Area.

3.10.1 Time Line for Network Operations Model Change Requests

(1) ERCOT shall perform periodic updates to the ERCOT Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process.

(3) TSPs and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. ERCOT shall update the Network Operations Model according to the following table:

Deadline to Submit Information to ERCOT **Note 1**	**Model Complete and Available for Test** **Note 2**	**Updated Network Operations Model Testing Complete** **Note 3**	**Update Network Operations Model Production Environment**	**Target Physical Equipment In-Service Date** **Note 4**
Jan 1	Feb 15	March 15	April 1	Month of April
Feb 1	March 15	April 15	May 1	Month of May
March 1	April 15	May 15	June 1	Months of June–August SUMMER MODEL
June 1	July 15	August 15	September 1	Month of September
July 1	August 15	September 15	October 1	Month of October
August 1	September 15	October 15	November 1	Month of November
September 1	October 15	November 15	December 1	Month of December
October 1	November 15	December 15	January 1	Month of January (the next year)
November 1	December 15	January 15	February 1	Month of February (the next year)
December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. Transmission and Resource data submissions complete per ERCOT Network Operations Model Change Request process for inclusion in next update period.

2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in Section 3.10.4(3). The test version of the Network Operations Model will be available for market review and further testing by Market Participants.
3. Testing of the Network Operations Model by Market Participants is complete and ERCOT begins the Energy Management System testing prior to placing the new model into the production environment.
4. Updates include changes starting at this date and ending within the same month.

(4) ERCOT shall only approve energization requests when the Transmission Element is satisfactorily modeled in the Network Operations Model.

(5) In order to allow for construction schedules, TSPs may use pseudo-breakers and switches to designate future facilities configurations such that the Network Operations Model topology may be correctly implemented as construction of new facilities is accomplished.

3.10.2 Annual Planning Model

(1) For each of the next five years, ERCOT shall develop models for annual planning purposes that contain, as much as practicable, information consistent with the Network Operations Model. The "Annual Planning Model" for each of the next five years is a model of the ERCOT power system (created, approved, posted, and updated regularly by ERCOT) as it is expected to operate during peak load conditions for the corresponding future year.

(2) ERCOT shall perform updates to the ERCOT Annual Planning Models for each of the next five years as follows:

(a) Annual Planning Model updates are due September 1st;

(b) Annual Planning Models are released October15th.

(3) ERCOT shall make available to TSPs and/or Distribution Service Provider (DSPs) and all appropriate Market Participants, consistent with applicable policies regarding release of Critical Energy Infrastructure Information (CEII), the transmission model used in transmission planning. ERCOT shall provide model information through the use of the Electric Power Research Institute (EPRI) and North American Electric Reliability Corporation (NERC) sponsored CIM and web-based XML communications.

(4) ERCOT shall establish a detailed submittal schedule for updating transmission information. ERCOT shall post such information and the model on the MIS Secure Area six months prior to the annual and two-year Congestion Revenue Rights (CRR) auctions.

(5) ERCOT shall coordinate updates to the Annual Planning Model with the Network Operations Model to ensure consistency of data within and between the Annual Planning Model and Network Operations Model to the extent practicable.

3.10.3 CRR Network Model

(1) ERCOT shall develop models for CRR auctions that contain, as much as practicable, information consistent with the Network Operations Model. Names of Transmission Elements in the Network Operations Model and the CRR Network Model must be identical for the same physical equipment.

(2) ERCOT shall verify that the names of Hub Buses and Electrical Buses used to describe the same device in any Hub are identically named in both the Network Operations Model and the CRR Network Model.

(3) Each CRR Network Model must include:

(a) A complete one-line diagram with all Settlement Points (indicating the Settlement Point that the Electrical Bus is a part of) and including all Hub Buses used to calculate Hub prices (if applicable);

(b) Generation Resource locations;

(c) Transmission Elements;

(d) Transmission impedances;

(e) Transmission ratings;

(f) Contingency lists;

(g) Data inputs used in the calculation of Dynamic Ratings, and

(h) Other relevant assumptions and inputs used for the CRR Network Model.

(4) ERCOT shall perform updates to CRR Network Model for CRR auctions as described in Section 7, Congestion Revenue Rights, a minimum of two months in advance.

(5) ERCOT shall make available to TSPs and/or DSPs and all appropriate Market Participants, consistent with applicable policies regarding release of Critical Energy Infrastructure Information (CEII), the CRR Network Model. ERCOT shall provide model information through the use of the Electric Power Research Institute (EPRI) and NERC-sponsored CIM and web based XML communications.

3.10.4 ERCOT Responsibilities

(1) ERCOT shall design, install, operate, and maintain its systems and establish applicable related processes to meet the Technical Advisory Committee (TAC) approved State Estimator (SE) performance standard for Transmission Elements that under typical system conditions potentially affect the calculation of Locational Marginal Prices (LMPs) as described in Section 3.10.7.5, Telemetry Criteria, and Section 3.10.9, State Estimator

Performance Standard. ERCOT shall post all documents relating to the State Estimator Performance Standard on the MIS Secure Area.

(2) During Real-Time, ERCOT shall calculate LMPs and take remedial actions to ensure that actual flow on a given Transmission Element is less than the Normal Rating and any calculated flow due to a contingency is less than the applicable Emergency Rating and 15-Minute Rating.

(3) ERCOT shall install Network Operations Model test facilities that will accommodate execution of a test Real-Time Sequence and preliminary test LMP calculator to demonstrate the correct operation of new Network Operations Models prior to releasing the model to Market Participants for detail testing and verification. The Network Operations Model test facilities support power flow and contingency analyses to test the data set representation of a proposed transmission model update and simulate LMP calculations using typical test data.

(4) ERCOT shall install Energy Management System test and simulation facilities that accommodate execution of the State Estimator and LMP calculator, respectively. These facilities will be used to conduct tests prior to placing a new model into ERCOT's production environment to verify the new model's accuracy. The Energy Management System test facilities allow a potential model to be tested before replacing the current production environment model. The Energy Management System test and simulation facilities must perform Real-Time Security Analysis to test a proposed transmission model before replacing the current production environment model. The Energy Management System State Estimation test facilities must have Real-Time ICCP links to test the state estimation function using actual Real-Time conditions. The Energy Management System LMP Test Facilities must accept data uploads from the production environment providing Qualified Scheduling Entity (QSE) Resource offers, and telemetry via ICCP. If the production data are unavailable, ERCOT may employ a data simulation tool or process to develop test data sets for the LMP Test Facilities. ERCOT shall acquire model comparison software that will show all differences between the next production model and production environment model and shall post this information on the MIS Secure Area within one week following test completion. This comparison shall indicate differences in device parameters, missing or new devices, and status changes.

(5) When implementing Transmission Element changes, ERCOT shall correct errors uncovered during testing that are due to submission of inaccurate information. Each TSP shall provide reasonably accurate information at the time of the original submission. ERCOT may update the model on an interim basis, outside of the timeline described in Section 3.10.1, Time Line for Network Operations Model Change Requests, for the correction of temporary configuration changes in a system restoration situation, such as after a storm, or correction of impedances and ratings. Interim updates to the Network Operations Model caused by unintentional inconsistencies of the model with the physical transmission grid may be made. If an interim update is implemented, ERCOT shall report changes to the PUCT staff and the Independent Market Monitor (IMM). ERCOT shall provide notice via electronic means to all Market Participants and post the notice on

the MIS Secure Area detailing the changed model information and the reason for the interim update within two Business Days following the report to PUCT staff and IMM.

(6) When ERCOT identifies active or binding transmission constraints on a repeated basis, ERCOT shall contact the appropriate TSP to:

(a) Verify that ratings of Transmission Facilities in the Network Operations Model and in the Updated Network Model causing the event are current and correctly represented;

(b) Verify, when the TSP's analysis results differ from those of ERCOT, that the configuration of the Transmission Grid in the Network Operations Model and in the Updated Network Model matches that in use by the TSP. To recognize operational time constraints, that verification must focus on Transmission Elements believed to have affected the event; and

(c) Mutually identify with the TSP any additional operational intervention or system monitoring that could be implemented to manage recurring congestion due to a recurring cause.

(7) A TSP, with ERCOT's assistance, shall validate its portion of the Network Operations Model according to the timeline provided in Section 3.10.1. ERCOT shall provide TSPs access, consistent with applicable policies regarding release of CEII, to an environment of the ERCOT Energy Management System where the Network Operations model and the results of the Real-Time State Estimator are available for review and analysis within five minutes of the Real-Time solution. This environment is provided as a tool to TSPs to perform power flow studies, contingency analyses and validation of State Estimator results.

(8) ERCOT shall make available to TSPs and other Market Participants, consistent with applicable policies regarding release of CEII, the full transmission model used to manage the reliability of the transmission system as well as proposed models to be implemented at a future date. ERCOT shall provide model information through the use of the Electric Power Research Institute (EPRI) and NERC-sponsored CIM and Web-based XML communications.

3.10.5 TSP Responsibilities

(1) Each TSP shall design, implement, operate, and maintain their systems to meet the TAC-approved ERCOT Telemetry Criteria under Section 3.10.7.5, for measurements facilitating the observability of the Electrical Buses used for Security-Constrained Economic Dispatch (SCED). However, there is no obligation to re-construct or retrofit already existing installations except as shown to be needed in order to achieve TAC-approved observability criteria and SE performance standard.

(2) TSPs shall add telemetry at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5. ERCOT shall request such

additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) Each TSP shall provide to ERCOT planned construction information, including CCN application milestone dates if applicable, all of which shall be updated quarterly according to a schedule established by ERCOT.

(4) Each TSP shall provide to ERCOT project status updates of Transmission Facilities that are part of an Relieability Must-Run (RMR) or Must Run Alternative (MRA) exit strategy corresponding to a specific RMR or MRA Agreement that has not been terminated, which shall be updated by the first Business Day of each month, noting any acceleration or delay in planned completion date.

3.10.6 Resource Entity Responsibilities

(1) QSEs and Resource Entities shall provide ERCOT and TSPs with information describing each Generation Resource and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

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

3.10.7 ERCOT System Modeling Requirements

The following sections contain the fidelity requirements for the ERCOT Network Operations Model.

3.10.7.1 Modeling of Transmission Elements and Parameters

(1) ERCOT, each TSP, and each Resource Entity shall coordinate to define each Transmission Element such that the TSP's control center operational model and ERCOT's Network Operations Model are consistent.

(2) Each Transmission Element must have a unique identifier using a consistent naming convention used between ERCOT and TSPs. ERCOT shall develop the naming convention with the assistance of the TSP and the approval of TAC. The Transmission Element naming convention must be based on a methodology that uses a prefix that uniquely identifies the TSP, followed by the name of the equipment used by the TSP. In addition to the Network Operations Model releases described in Section 3.10.1, Time Line for Network Operations Model Change Requests, ERCOT shall provide all names and parameters of all Transmission Elements to Market Participants posted on MIS Secure Area by 0600 each day.

(3) If the responsible TSP submits an NOMCR for non-operational changes, such as name changes for Transmission Elements, ERCOT shall implement the request.

3.10.7.1.1 Transmission Lines

(1) ERCOT shall model each transmission line that operates in excess of 60kV.

(2) For each of its transmission lines operated as part of the ERCOT Transmission Grid, each TSP shall provide ERCOT with the following information consistent with the ratings methodology prescribed in the ERCOT Operating Guides:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) Transmission Element name;

(d) Line impedance;

(e) "From" and "to" Electrical Buses information;

(f) Line type (overhead or cable);

(g) Normal Rating, Emergency Rating, and 15-Minute Rating; and

(h) Other data necessary to model Transmission Element(s).

(3) The TSP may submit special transfer limits and stability limits for secure and reliable grid operations for ERCOT approval. ERCOT has sole decision-making authority and responsibility to determine the limits to be applied in grid operations.

(4) The TSP may implement protective relay and control systems and set values appropriate to de-energize faulted equipment and meet the TSP obligations for public or employee safety, and when necessary to prevent in-service or premature equipment failure consistent with Good Utility Practice and accepted industry standards. The TSP shall include those limits when providing ERCOT with ratings or proposed transfer limits.

(5) The Network Operations Model must use rating categories for Transmission Elements as defined in the ERCOT Operating Guides.

3.10.7.1.2 Transmission Buses

(1) ERCOT shall model each Electrical Bus that operates as part of the ERCOT Transmission Grid in excess of 60kV and that is required to model switching stations or transmission Loads.

(2) Each TSP shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) A description of all transmission circuits that may be connected through breakers or switches; and

(f) Other data necessary to model Transmission Element(s).

(3) To accommodate the Outage Scheduler, the TSP may define a separate name and Transmission Element for any electrical bus that can be physically separated by a manual switch or breaker within a substation.

3.10.7.1.3 Transmission Breakers and Switches

(1) ERCOT's Network Operations Model must include all transmission breakers and switches, the operation of which may cause a change in the flow on transmission lines or Electrical Buses. Breakers and switches may only be connected to defined Electrical Buses.

(2) Each TSP shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Connectivity;

(f) Normal status; and

(g) Other data necessary to model Transmission Element(s).

(3) ERCOT shall develop methods to accurately model changes in transmission line loading resulting from Load rollover schemes transferring more than ten MW. This may include modeling distribution circuit breakers, dead line sensing, or other methods that signal when the load should be transferred from one transmission line to another transmission

line. ERCOT may employ heuristic rule sets for all manual load transfers and for automated transfers where feasible. ERCOT application software is required to model the effects of automatic or manual schemes in the field transfer load under line outage conditions. Each TSP shall define the Load rollover schemes under Section 3.10.7.2, Modeling of Resources and Transmission Loads, and furnish this information to ERCOT. Transmission field (right-of-way) switches must be connected to a named Electrical Bus and be included in the Network Operations Model.

3.10.7.1.4 Transmission and Generation Resource Step-Up Transformers

(1) ERCOT shall model all transformers with a nominal low side (i.e., secondary, not tertiary) voltage above 60 kV.

(2) ERCOT shall model all Generation Resource step-up transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under load, accept telemetry of the current tap position.

(3) Each TSP and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary load as required by ERCOT. Each TSP and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Winding ratings;

(f) Connectivity;

(g) Transformer parameters, including all tap parameters; and

(h) Other data necessary to model Transmission Element(s).

(4) The Generation Entity shall provide parameters for each step-up transformer to ERCOT, which shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to establish the proper transformer tap positions (no-load taps) and report any changes to ERCOT using the NOMCR process or other ERCOT prescribed means. Each Generation Entity and each TSP shall schedule Generation Outages at mutually agreeable times to implement tap position changes when necessary. If mutual agreement cannot be reached, then ERCOT

shall decide where to set the tap position to be implemented by the Generation Entity at the next Generation Outage, considering expected impact on system security, future Outage plans, and participants. TSPs shall provide ERCOT and Market Participants with notice in accordance with 3.10.4, ERCOT Responsibilities, paragraph (4) (except for emergency) prior to the tap position change implementation date.

(5) ERCOT shall post to the MIS Secure Area information regarding all transformers represented in the Network Operations Model.

3.10.7.1.5 Reactors, Capacitors, and other Reactive Controlled Sources

(1) ERCOT shall model all controlled reactive devices. Each Market Participant shall provide ERCOT with complete information on each device's capabilities and normal switching schema.

(2) Each Market Participant shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Voltage or time switched on;

(f) Voltage or time switched off;

(g) Associated switching device name;

(h) Connectivity;

(i) Nominal voltage and associated capacitance or reactance; and

(j) Other data necessary to model Transmission Element(s).

(3) The ERCOT Operating Guides must include parameters for standard reactor and capacitor switching plans for use in the Network Operations Model. ERCOT shall model the devices under Section 3.10.4, ERCOT Responsibilities, in all applicable ERCOT applications and systems. ERCOT shall provide copies of the switching plan to the Market Participants via the MIS Secure Area. Any change in TSP guidelines or switching plan must be provided to ERCOT before implementation (except for emergency). Any change in guidelines or switching plan must be provided in accordance with the NOMCR process or other ERCOT-prescribed process.

3.10.7.2 Modeling of Resources and Transmission Loads

(1) Each Resource Entity shall provide ERCOT and TSPs with information describing each of its Generation Resources and Load Resources connected to the transmission system. All Resources greater than ten MW, Generation Resources less than ten MW but providing Ancillary Service, Split Generation Resources, Private Use Networks containing Resources greater than ten MW, Direct Current Tie (DC Tie) Resources, and the non-TSP owned step-up transformers greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, DC Tie Resources and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

(2) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the Generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations for Split Generation Meters. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the Generation facility main power transformer.

(3) ERCOT shall create a DC Tie Resource to represent an equivalent generation injection to represent the flow into the ERCOT Transmission Grid from operation of DC Ties. The actual injection flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Resource output.

(4) TSPs shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a Model Load to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load cannot be used to represent Load connections that are in different Load Zones.

(5) ERCOT may require TSPs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5. When the TSP does not own the station for which additional load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP shall notify ERCOT if the owner does not comply with the request.

(6) ERCOT shall create a DC Tie Load to represent an equivalent Load withdrawal to represent the flow from the ERCOT Transmission Grid from operation of DC Ties. The actual withdrawal flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Load output.

(7) Each TSP shall also provide information to ERCOT describing automatic Load transfer (rollover) plans and the events that trigger which Loads are switched to other

Transmission Elements on detection of outage of a primary Transmission Element. ERCOT shall accommodate load rollover plans in the Network Operations Model

(8) Loads associated with a Generation Resource in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT Polled Settlement Meters, and served through a transformer owned by the Generation Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3, Generation Netting for ERCOT Polled Settlement Meters.

3.10.7.3 Modeling of Private Use Networks

ERCOT shall create and use network models describing Private Use Networks according to the following:

(1) A Generation Entity with a Resource located within a Private Use Network shall provide data to ERCOT, for use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network in accordance with the Protocols if it meets any one of the following criteria:

(a) Contains a generator greater than ten MW and is registered with the PUCT according to P.U.C. SUBST. R. 25.109, Registration of Power Generation Companies and Self-Generators, as a power generation company; or

(b) Is part of a Private Use Network which contains more than one connections to the ERCOT Transmission Grid; or

(c) Contains generation registered to provide Ancillary Services,

(2) A Generation Entity with a generator greater than ten MW located within a Private Use Network which does not meet any of the criteria of item (1) above, shall provide to ERCOT annually, or more often upon change, the following information for ERCOT's use in the Network Operations Model, for each of its individual generating unit(s) located within the Private Use Network:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) TSP substation name connecting the Private Use Network to the ERCOT System;

(d) At the request of ERCOT, a description of Transmission Elements within the Private Use Network that may be connected through breakers or switches;

(e) Net energy delivery metering, as required by ERCOT, to and from a the Private Use Network and the ERCOT System at the point of interconnection with the TSP;

(f) For each individual generator located within the Private Use Network, the gross capacity in MW and its reactive capability curve;

(g) Maximum and minimum reasonability limits of the Load located within the Private Use Network;

(h) Outage schedule for each generation unit located within the Private Use Network, updated as changes occur from the annually submitted information; and

(i) Other interconnection data as required by ERCOT.

(3) Energy delivered to ERCOT from a non-modeled generator shall be settled in accordance with Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone.

(4) ERCOT shall ensure the Network Operations Model properly models the physical effect of the loss of generators and Transmission Elements on the ERCOT Transmission Grid equipment loading, voltage, and stability.

(5) ERCOT may require the owner or operator of a Private Use Network to provide information to ERCOT and the TSP on Transmission Facilities located within the Private Use Network for use in the Network Operations Model if the information is required to adequately model and determine the security of the ERCOT Transmission Grid, including data to perform loop flow analysis of Private Use Networks.

(6) ERCOT shall review submittals of modeling data from owners or operators of Private Use Networks assure that it will result in correct analysis of ERCOT Transmission Grid security.

3.10.7.4 Definition of Special Protection Systems and Remedial Action Plans

(1) All Special Protection Systems (SPSs) and Remedial Action Plans (RAPs) used by ERCOT and the TSPs to maintain a secure system must be defined in the Network Operations Model.

(2) Proposed new SPSs and RAPs and proposed changes to SPSs and RAPs must be submitted to ERCOT for review and approval by ERCOT and all directly affected TSPs and Resource Entities under the applicable procedures in the Operating Guides. Once a new or changed SPS or RAP is approved by ERCOT and all directly affected TSPs and Resource Entities, the TSP shall submit the approved SPS or RAP to ERCOT using an NOMCR. The NOMCR must include a detailed description of the system conditions required to implement the SPS or RAP. Execution of an SPS or RAP must be included or assumed in the calculation of LMPs as well as the Network Operations Model. ERCOT shall post all SPSs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt by ERCOT.

(3) ERCOT shall model, and include in the Security Analysis, approved SPSs and RAPs. ERCOT shall post on the MIS Secure Area all approved SPSs and RAPs at least two Business Days before implementation, identifying the date of implementation.

3.10.7.5 Telemetry Criteria

(1) The appropriate TAC subcommittee shall establish a task force that is open to Market Participants, comprised of technical experts to develop a set of Telemetry Criteria consistent with the minimum requirements of the Protocols. TAC shall approve a set of Telemetry Criteria and the appropriate TAC subcommittee shall update the Telemetry Criteria annually each October or more often on a periodic basis as deemed necessary.

(2) The Telemetry Criteria must define the performance and observability requirements of voltage and power flow measurements, including requirements for redundancy of telemetry measurement data, necessary to support the State Estimator in meeting the approved performance standard, and to support TAC-approved accuracy standards for the calculation of LMPs.

(3) The telemetry provided to ERCOT by each TSP must be updated at a 10 second or less scan rate and be provided to ERCOT at the same rate. Each TSP and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP and QSE. ERCOT shall represent data condition codes from each TSP and QSE in a consistent manner for all applicable ERCOT applications.

(4) Each TSP and QSE shall use fully redundant data communication links (ICCP) between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

(5) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Model Loads, and that concern or deficiency is not due to any inadequacy of the State Estimator program, ERCOT may request that a TSP or QSE provide additional telemetry measurements, beyond those required by the Telemetry Criteria, in a reasonable time frame for providing such measurements. Such requests must be submitted to the TSP or QSE with a written justification for the additional telemetry measurements. Such written justification must include documentation of the deficiency in system observability or representation of

Model Loads. In making the determination to request additional telemetry measurements, ERCOT shall consider the economic implications of inaccurate representation of Load Models in LMP results versus the cost to remedy.

(6) Within 30 days of submittal by ERCOT to the designated contact of a TSP or QSE with a written request justifying additional telemetry measurements, the TSP or QSE shall acknowledge the request and either:

(a) Agree with the request and make reasonable effort to install new equipment providing measurements to ERCOT within the timeframe specified;

(b) Provide ERCOT an analysis of the cost to comply with the request, so that, ERCOT can perform a cost justification with respect to the LMP market; or

(c) If the TSP or QSE disagrees with the request, appeal that request to TAC or present an alternate solution to ERCOT for consideration.

(7) If ERCOT rejects the alternate solution, the TSP or QSE may appeal the original request to TAC within 30 days. If, after receiving an appeal, TAC does not resolve the appeal within 65 days, the TSP or QSE may present its appeal to the ERCOT Board. Notwithstanding the foregoing, a TSP or QSE is not required to provide telemetry measurements from a location not owned by that TSP or QSE, if the location owner does not grant access to the TSP or QSE for the purpose of obtaining such measurements. ERCOT shall report such cases to the IMM.

3.10.7.5.1 Continuous Telemetry of the Status of Breakers and Switches

(1) Each TSP and QSE shall provide telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches used to switch any Transmission Element or load modeled by ERCOT. Each TSP and QSE is not required to install telemetry on individual breakers and switches, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP or QSE switching operations and TSP or QSE personnel. Each TSP or QSE shall update the status of any breaker or switch through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute. If in the sole opinion of ERCOT, the manual updates of the TSP or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Performance Standard, ERCOT may request that the TSP or QSE install complete telemetry from the breaker or switch to the TSP or QSE, and then to ERCOT. In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Model Loads in LMP results versus the cost to remedy.

(2) ERCOT shall measure TSP or QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

(3) Unless there is an emergency condition, a TSP or QSE must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, a TSP or QSE must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

(4) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for Security Analysis as updated by the Outage Scheduler and through verbal communication with the TSP or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

(5) ERCOT shall establish a system that provides alarms to ERCOT operators when there is a change in status of any monitored transmission breaker or switch, and an indication of whether the device change of status was planned in the Outage Scheduler. ERCOT operators shall monitor any changes in status not only for reliability of operations, but also for accuracy and impact on the operation of the SCED functions and subsequent potential for calculation of inaccurate LMPs.

(6) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, shall provide ERCOT with telemetry of the actual generator breakers and switches continuously providing ERCOT with the status of the individual Split Generation Resource.

3.10.7.5.2 Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows

(1) Each TSP or QSE shall provide telemetry of voltages, flows, and Loads on any modeled Transmission Element to the extent such may be required to estimate all transmission Load withdrawals and generation injections to and from the ERCOT Transmission Grid using the State Estimator and as needed to achieve the TAC-approved SE performance standard with consideration given to the economic implications of inaccurate LMP results versus the cost to remedy.

(2) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations for Split Generation Meters, shall provide ERCOT with telemetry of the actual equivalent generator injection of its individual Split Generation Resource and with telemetry of the total generation injection of the total generation facility. ERCOT shall calculate the sum of each QSE's telemetry on an individual Split Generation Resource and compare the sum to the telemetry for the total generation facility. ERCOT shall notify each QSE representing the Split Generation Resource of any errors in telemetry detected by the State Estimator.

(3) Each TSP shall provide telemetered measurements on modeled Transmission Elements to ensure State Estimator observability, per TAC-approved Telemetry Criteria, of any monitored voltage and power flow between their associated transmission breakers to the extent such can be shown to be needed in achieving the TAC-approved SE performance standard. On monitored non-Load substations, each TSP shall install, at the direction of ERCOT, sufficient telemetry such that there is an "N-1 Redundancy." An N-1 Redundancy exists if the substation remains observable on the loss of any single measurement pair (kW, kVar) excluding station RTU communication path failures. In making the determination to request additional telemetry, ERCOT shall consider the economic implications of inaccurate representation of Load Models in LMP results versus the cost to remedy.

(4) The accuracy of the State Estimator is critical to successful market operations. For this reason it is a critical objective for ERCOT to maintain reasonable and accurate results of the State Estimator. ERCOT shall use all reasonable efforts to achieve that objective, including the provision of legitimate constraints used in calculating LMPs.

(5) Each TSP, QSE and ERCOT shall develop a continuously operated program to maintain telemetry of all Transmission Element measurements to provide accurate results using TAC-approved accuracy standards from the State Estimator. For any location where there is a connection of multiple, measured, Transmission Elements, ERCOT shall have an automated process to detect and notify ERCOT system operators if the residual sum of all telemetered measurements is more than (a) five percent of the largest line rating at the Electrical Bus or (b) five MW, whichever is greater. If a location chronically fails this test, ERCOT shall notify the applicable TSP or QSE and suggest actions that the TSP or QSE could take to correct the failure. Within 30 days, the TSP or QSE shall take the actions necessary to correct the failure or provide ERCOT with a detailed plan with a projected timeframe to correct the failure. ERCOT shall post a notice on the MIS Secure Area of any Electrical Buses not meeting TAC-approved accuracy requirements, including a list of all measurements and the residual errors on a monthly basis.

(6) ERCOT shall implement a study mode version of the State Estimator with special tools designed for troubleshooting and tuning purposes that can be used independently of any other ERCOT process that is dependant on the real time State Estimator. ERCOT shall implement a process to recognize inaccurate State Estimator results and shall create and implement alternative Real-Time LMP calculation processes for use when inaccurate results are detected. ERCOT must be guided in this by TAC-approved accuracy standards.

(7) ERCOT shall establish a system to provide overload and over/under limit alarming on all Transmission Elements monitored as constraints in the LMP models.

3.10.7.6 Modeling of Generic Transmission Limits

(1) For the sole purpose of creating transmission flow constraints between areas of the ERCOT Transmission Grid for systems unable to recognize system stability limits and

voltage limits on Electrical Buses, ERCOT may create GTLs for use in reliability and market analysis. ERCOT shall not use GTLs for constraints in ERCOT systems capable of being directly modeled as security actions required to enforce stability and voltage limits.

(2) Except as provided in (3) below, ERCOT shall post all GTLs on the MIS Secure Area no later than the day prior to the GTL becoming effective in any ERCOT application. Posting of GTLs shall include the identity of all constrained transmission flows, old limits, if applicable, and new flow limits, effective date, and an explanation for each flow limit and for the change, if applicable. ERCOT shall provide detailed information on the methodology, including data and studies used for determination of each GTL, on the MIS Secure Area. Market Participants may review and comment on ERCOT's methodology. Within seven days following receipt of any comments, ERCOT shall post the comments with the subject GTL.

(3) If an unexpected change to ERCOT System conditions requires a new GTL to manage ERCOT System reliability not posted pursuant to (2) above, ERCOT will declare an Alert and post on the MIS Secure Area the new GTL, including the detail information described above. ERCOT shall include an explanation regarding why it did not post the limit change on the previous day.

3.10.8 Dynamic Ratings

(1) ERCOT shall use Dynamic Ratings, where available, in the Network Operations Model, Annual Planning Models, and the CRR Network Models.

(2) ERCOT shall use Dynamic Ratings in place of the Normal Rating, Emergency Rating and 15-Minute Rating as applicable as provided under paragraphs (a) or (b) below for Transmission Elements established in the Network Operations Model.

(a) A TSP may provide Dynamic Ratings via ICCP for implementation in the next Operating Hour. ERCOT shall use the Dynamic Ratings in its Supervisory Control and Data Acquisition (SCADA) alarming, real-time Security Analysis, and SCED process. In addition, the TSP shall provide ERCOT with a table of equipment rating versus temperature for use in operational planning studies.

(b) Each TSP may alternatively elect to provide ERCOT with a table of equipment rating versus temperature and a temperature values in Real-Time for each Weather Zone in which the Transmission Element is located. ERCOT shall apply the table of temperature and rating relationships and ERCOT's current temperature measurements to determine the rating of each such designated piece of equipment for each Operating Hour. ERCOT shall use the TSP-provided table in operational planning studies.

(3) Each Operating Hour, ERCOT shall post on the MIS Secure Area updated Dynamic Ratings adjusted for the current temperature.

(4) ERCOT may request that a TSP submit temperature-adjusted ratings on Transmission Elements that ERCOT identifies as contributing to significant congestion costs. Each TSP shall provide the additional ratings within two months of such a request using one of the two mechanisms for supplying temperature-adjusted ratings identified above. Ratings for Transmission Elements operated by multiple TSPs must be supplied by each TSP that has control. ERCOT shall use the most limiting rating and report the circumstance to the IMM.

3.10.8.1 Dynamic Ratings Delivered via ICCP

(1) The TSP shall supply the following, via ICCP, updated at least every ten minutes:

(a) Line ID;

(b) From station;

(c) To station; and

(d) Each of the three ratings: Normal Rating, Emergency Rating, and 15-Minute Rating.

(2) ERCOT shall link each provided line rating with the ERCOT Network Operations Model and implement the ratings for the next Operating Hour. ERCOT shall use the Dynamic Ratings in its SCADA alarming, real-time Security Analysis, and SCED process. When the telemetry is not operational, ERCOT shall use a temperature appropriate for current conditions, and employ the required Dynamic Rating lookup table to determine the appropriate rating. .

3.10.8.2 Dynamic Ratings Delivered via Static Table and Telemetered Temperature

(1) ERCOT shall define a set of tables implementing the dynamic characteristics provided by the TSP(s) of selected transmission lines, including:

(a) Line ID;

(b) From station;

(c) To station;

(d) Weather Zone(s);

(e) TSP(s); and

(f) Each of the three ratings: Normal Rating, Emergency Rating, and 15-Minute Rating.

(2) ERCOT shall link each transmission line defined in these tables to one SCADA point providing the temperature used to calculate Dynamic Ratings. Each TSP shall provide a current temperature for each applicable Weather Zone through SCADA telemetry. ERCOT shall determine the appropriate rating based upon the telemetered temperature, and adjust the Normal Rating, Emergency Rating, and 15-Minute Rating within five minutes of receipt for the next Operating Hour. ERCOT shall use the Dynamic Ratings in its SCADA alarming, real-time Security Analysis, and SCED process. On loss of telemetry, the TSP shall manually provide updated temperatures to ERCOT for entry in the SCADA system.

3.10.8.3 Dynamic Rating Network Operations Model Change Requests

ERCOT shall use the NOMCR process by which TSPs provide electronically to ERCOT the dynamic rating table described in Section 3.10.8.2, Dynamic Ratings Delivered via Static Table and Telemetered Temperature.

3.10.8.4 ERCOT Responsibilities Related to Dynamic Ratings

(1) ERCOT shall provide a system to accept and implement Dynamic Ratings or temperatures to be applied to rating tables for each hour in the Day-Ahead and in the Operating Hour. ERCOT shall also:

(a) Provide software and processes that allow secure access for TSPs and Market Participants and that maintains a log of data provided and the actions of the TSP and ERCOT, to implement the Dynamic Ratings as described above; (b) Use Dynamic Ratings for alarming, compliance with ERCOT and NERC requirements, and SCED purposes in both Real-Time Operations and operational planning;

(c) Approve or reject the new dynamic rating request within 24 hours of receipt; and

(d) Implement the approved dynamic rating automatically within 24 hours of approval.

(2) ERCOT shall provide a system to implement Dynamic Ratings and to obtain monthly expected ambient air temperatures to be applied to rating tables for the Annual Planning Models and the CRR Network Models. Temperatures applied to the rating tables shall be determined using the same method as described in subparagraph (3)(f) of Section 7.5.5.4, Simultaneous Feasibility Test. Transmission Elements that have Dynamic Ratings implemented in the Network Operations Model must have Dynamic Ratings in the Annual Planning Models and CRR Network Models.

(3) ERCOT shall identify additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through Dynamic Rating and request such Dynamic Ratings from the associated TSP. ERCOT shall post

semi-annually the list of the Transmission Elements and identify if the TSP has agreed to provide the rating on the MIS Secure Area.

3.10.8.5 Transmission Service Provider Responsibilities Related to Dynamic Ratings

Each TSP shall:

(a) Provide ERCOT with tables of ratings for different ambient temperatures for Transmission Elements, as requested by ERCOT.

(b) Submit within two months a temperature adjusted rating table when a request is received from ERCOT unless multiple requests are made by ERCOT within the two-month period or unusual circumstances prevent the request from being accommodated in a timely fashion. Such circumstances must be explained to ERCOT in writing and must be posted by ERCOT on the MIS Secure Area within five Business Days of receipt.

(c) Provide Real-Time temperatures for each Weather Zone in which the TSP has existing dynamically rated transmission equipment, or alternatively provide rating updates for each temperature-adjusted line rating updated at least once every ten minutes.

3.10.9 State Estimator Performance Standard

(1) The appropriate TAC subcommittee shall establish a task force that is open to Market Participants, comprised of technical experts to develop a State Estimator Performance Standard consistent with the minimum requirements of the Protocols. TAC shall approve the State Estimator Performance Standards, and the appropriate TAC subcommittee shall update the State Estimator Performance Standards annually each October or more often on a periodic basis as deemed necessary.

(2) The State Estimator Performance Standard must define the performance requirements necessary to provide State Estimator results within a TAC-defined level of confidence and results for LMP calculation that meet TAC-approved accuracy standards. The appropriate TAC subcommittee shall coordinate with Market Participants to ensure a common understanding of the level of State Estimator performance required to enable LMP calculation that meets TAC-approved accuracy standards. Further, the standard must address the State Estimator's ability to detect, correct, or otherwise accommodate communications system failures, failed data points, stale data condition codes, and missing or inaccurate measurements to the extent these capabilities contribute to LMP accuracy and State Estimator performance or as needed to meet reliability requirements.

3.10.9.1 Considerations for Performance Standards

In developing the State Estimator Performance Standard recommendations to TAC, the following may be considered:

(a) Desired confidence levels of State Estimator results.

(b) Measurement requirements to estimate power injections and withdrawals at transmission voltage Electrical Buses defined in the SCED transmission model, which may provide for variations in criteria based on:

(i) The number of Transmission Elements connected to a given transmission voltage Electrical Bus;

(ii) The peak demand of the Load connected to a transmission voltage Electrical Bus;

(iii) The total of Resource capacity connected to a transmission voltage Electrical Bus;

(iv) The nominal transmission voltage level of a Electrical Bus;

(v) The number of Electrical Buses with injections or withdrawals along a circuit between currently monitored transmission voltage Electrical Bus;

(vi) Connection of Loads along a continuous, non-branching circuit that may be combined for modeling purposes;

(vii) The quantity of Load at a Electrical Bus that may have its connection to the transmission system automatically transferred to an Electrical Bus other than the one to which it is normally connected (rollover operation);

(vii) Electrical proximity to more than one Resource Node;

(viii) Degree or quality of continued observability following the loss of telemetry measurements resulting from a common mode failure of telemetry-related equipment (*i.e.*, an N-1 telemetry condition); and

(ix) Other parameters or circumstances, as appropriate;

(c) Sensitivity of State Estimator results with respect to variations in input parameters;

(d) Reasonable safeguards to assure State Estimator results are calculated on a non-discriminatory basis; and

(e) Other parameters as deemed appropriate.

3.10.9.2 Telemetry and State Estimator Performance Monitoring

ERCOT shall monitor the performance of the State Estimator, Network Security Analysis, SCED, and LMP Calculator. ERCOT shall post a monthly report of these items on the MIS Secure Area. ERCOT shall notify affected TSPs of any lapses of observability of the transmission system.

3.11 Transmission Planning

3.11.1 Overview

(1) ERCOT shall supervise and exercise comprehensive independent authority of the overall planning of transmission projects of the ERCOT Transmission Grid as outlined in the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. (Vernon 1998 & Supp. 2003)(PURA) and Public Utility Commission of Texas (PUCT) Substantive Rules. ERCOT's authority with respect to transmission projects that are local in nature is limited to supervising and coordinating the planning activities of Transmission Service Providers. The PUCT Substantive Rules further indicate that the Independent Operator shall evaluate and make a recommendation to the PUCT as to the need for any Transmission Facility over which it has comprehensive transmission planning authority.

(2) Any Market Participant, regardless if it is a TSP and/or DSP, may develop and submit proposed projects to the Regional Planning Groups (RPGs), and review projects developed and proposed by the RPGs. Broad participation in the process will result in a thorough development of projects. However, confidentiality provisions prevent participation of non-TSPs and/or DSPs in the studies leading to interconnection agreements with generators until they become public.

(3) Project endorsement through the ERCOT Regional Planning process is intended to support, to the extent applicable, a finding by the PUCT that a project is necessary for the service, accommodation, convenience, or safety of the public within the meaning of, PURA §37.056, Grant or Denial of Certificate, and P.U.C. SUBST. R. 25.101, Certification Criteria.

(4) The data within and between the Annual Planning Model and the Network Operations Model shall be coordinated to ensure consistency within and between the Annual Planning Model and the Network Operations Model.

3.11.2 Planning Criteria

(1) ERCOT and Transmission Service Providers shall evaluate the need for transmission system improvements in accordance with Section 3.11.1, Overview, paragraph (1), and shall evaluate the relative value of alternative improvements based on established technical and economic criteria.

(2) The technical reliability criteria are established by the ERCOT Operating Guides and the NERC planning criteria. ERCOT and TSPs shall strongly endeavor to meet these criteria, identify current and future violations thereof and initiate solutions necessary to ensure continual compliance, except that solutions requiring Transmission Facility Outages within the 12 months following development of such solution must be excluded from any reported metric on the TSP's 12-month Outage forecasting performance under Section 3.1.3.1, Transmission Facilities.

(3) ERCOT shall attempt to meet these reliability criteria as economically as possible and shall actively identify Economic Projects to meet this goal. An "Economic Project" is a proposed system improvement that has a net economic benefit to the market, as determined by a reduction in expected costs to the market that exceed the incremental cost of the system improvement on a net present value basis. Specifically, ERCOT shall initiate a study of potential Economic Projects as an exit strategy from RMR contract or where the congestion costs exceed a specified threshold. In situations where several alternative system improvements have been identified that meet the reliability criteria, the project that has the highest net economic benefit to the market must be preferred. The evaluation of Economic Projects must be based on forecasted conditions during the time period for which data is reasonably available.

3.11.3 Regional Planning Groups

(1) ERCOT shall lead Regional Planning Groups (RPG) to consider and review proposed projects to address transmission constraints and other system needs. Participation in the Regional Planning Groups is required of all TSPs and is open to all Market Participants, consumers, and PUCT Staff. ERCOT is responsible for leading and facilitating the RPG processes.

(2) The goals of these Regional Planning Groups are:

(a) Coordinate transmission planning and construction to ensure that the ERCOT and NERC planning standards are met, that a proposed project addresses ERCOT planning criteria requirements, and that transmission upgrades address needs;

(b) Improve communication and understanding between neighboring TSPs on operating procedures, SPSs and RAPs that respond to contingencies, voltage deviations, and facility overloads;

(c) Prevent inefficient solutions to regional problems through a coordinated effort and resolving the needs of the interconnected transmission systems while ensuring a reliable and adequate network;

(d) Seek a cost-effective balance between costs and lead times in the plans produced to ensure and maintain reliable service;

(e) Assist ERCOT operations personnel to develop coordinated SPSs to address actual or likely transmission system inadequacies, as interim measures until a permanent solution is identified, or as permanent measures in situations where system improvement is impractical or uneconomic;

(f) Evaluate SPS and RAP exit strategies to determine whether there is a practical and economic system improvement to remedy inadequacies requiring SPSs or RAPs;

(g) Allow Market Participant and consumer review of major proposed transmission project additions, as outlined in the ERCOT Planning Charter; and

(h) To the extent not already provided for under generation interconnection procedures and interconnection agreements, integrate new Generation Resources, including renewable technologies, under PUCT Substantive Rules and Legislative mandates.

3.11.4 Transmission Planning Responsibilities

(1) ERCOT, shall monitor the differences in Locational Marginal Prices from the Security-Constrained Economic Dispatch process to identify geographic areas potentially experiencing chronic congestion. On determination of chronic congestion, ERCOT shall:

(a) Validate with the TSP that the data from the Network Operating Model and the Updated Network Model are correct. If the models are valid, ERCOT shall use the planning criteria in the transmission planning process, through the appropriate Regional Planning Group, to develop recommendations for resolution, if applicable.

(b) Post all the results from this process on the MIS Secure Area and provide them to the PUCT Staff, the Independent Market Monitor (IMM), the appropriate ERCOT subcommittee(s), and the ERCOT Board of Directors.

(2) ERCOT and TSP responsibilities for planning of the ERCOT Transmission Grid are those described in Section 5, Planning, of the Operating Guides.

3.12 Load Forecasting

ERCOT shall produce and use Load forecasts to serve operations and planning objectives.

(a) ERCOT shall update and post hourly on the MIS Secure Area a "Seven-Day Load Forecast" that generates forecasted hourly Load over the next 168 hours for each of the Weather Zones and for each of the Forecast Zones.

(b) ERCOT shall update and post monthly on the MIS Secure Area a "36-Month Load Forecast" that provides a daily minimum and maximum forecast for the next 36-months for each of the Weather Zones and for each of the Forecast Zones.

3.12.1 Seven-Day Load Forecast

(1) ERCOT shall use the Seven-Day Load Forecast to predict hourly Loads for the next 168 hours based on current weather forecast parameters within each Weather Zone. Preparation for Day-Ahead Operations requires an accurate forecast of the Loads for which generation capacity must be secured. The Seven-Day Load Forecast must have a "self-training" mode that allows ERCOT to review historic Load data and provide the ability to retrain the Seven-Day Load Forecast algorithm.

(2) The inputs for the Seven-Day Load Forecast are as follows:

(a) Hourly forecasted weather parameters for the weather stations within the Weather Zones, which are updated at least once per hour; and

(b) Training information based on historic hourly integrated Weather Zone Loads.

(3) ERCOT shall review the forecast suggested by Seven-Day Load Forecast and shall use its judgment, if necessary, to modify the result prior to implementation in the Ancillary Service capacity Monitor, DRUC, HRUC, and Resource adequacy reporting.

3.12.2 36-Month Load Forecast

(1) ERCOT shall use the 36-Month Load Forecast to predict daily minimum and maximum Loads for the next 36 months. An accurate 36-Month Load Forecast is required to perform Outage Coordination, Resource adequacy reporting and other Operations analysis for the three years ahead.

(2) ERCOT shall review the forecast suggested by the 36-Month Load Forecast and shall use its judgment if necessary to modify the result before implementation and posting on the MIS Secure Area.

3.13 Renewable Production Potential Forecasts

(1) ERCOT shall produce forecasts of Renewable Production Potential (RPP) for Wind-powered Generation Resources (WGR) to be used as an input into the Day-Ahead Reliability Unit Commitment (DRUC) and Hour-Ahead Reliability Unit Commitment (HRUC). ERCOT shall produce the forecasts using information provided by WGR Entities, meteorological information, and SCADA. WGR Entities shall install telemetry at their WGRs and transmit the ERCOT-specified site-specific meteorological information to ERCOT. WGR Entities shall also provide detailed equipment status at the WGR facility as specified by ERCOT to support the RPP forecast. ERCOT shall provide forecasts for each WGR to the QSEs representing WGRs. QSEs shall use the ERCOT-provided forecasts for WGRs throughout the Day-Ahead and Operating Day for applicable markets and RUCs. Similar requirements for solar power and run-of-the-river hydro must be developed as needed.

(2) WGR Entities shall provide ERCOT and their respective QSEs with Long-Term Wind Power Forecast (LTWPF) profiles for each WGR having an aggregated rating larger than 10 MW at its point of interconnection with the transmission system. The profiles must forecast the daily generation shape by hourly production of wind power Renewable Production Potential and the WGR Entities shall provide the profiles to ERCOT for each month on a rolling 36 month basis.

(3) ERCOT shall develop cost-effective tools or services to forecast energy production from IRRs with technical assistance from QSEs scheduling Renewable Resources. ERCOT shall use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. ERCOT shall post on the MIS Secure Area objective criteria and thresholds for unbiased, accurate forecasts within five Business Days of change.

3.14 Contracts for Reliability Resources and EILS Loads

ERCOT shall procure Reliability Must-Run (RMR) Service, Black Start Service or Emergency Interruptible Load Service (EILS) through Agreements.

3.14.1 Reliability Must Run

(1) RMR Service is the use by ERCOT, under contracts with Generation Entities, of capacity and energy from Generation Resources that otherwise would not operate and that are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria, as described in the ERCOT Operating Guides, where market solutions do not exist. This includes service provided by RMR Units and Must Run Alternative (MRA) Resources.

(a) Upon receiving notice from a Generation Entity as described in Section 3.14.1.1, Notification of Suspension of Operations, ERCOT may enter into RMR Agreements and begin procurement of RMR Service under this Section.

(b) Before entering into an RMR Agreement, ERCOT shall assess alternatives to the proposed RMR Agreement. The list of alternatives ERCOT must consider includes (as reasonable for each type of reliability concern identified):

(i) Redispatch/reconfiguration through operator instruction;

(ii) Remedial Action Plans;

(iii) Special Protection Systems (SPS) initiated on unit trips or Transmission Facilities Outages; and

(iv) Load response alternatives once a suitable Load response service is defined and available.

(c) ERCOT shall minimize the use of RMR Units as much as practicable subject to the other provisions of these Protocols. ERCOT may Dispatch an RMR Unit at any time for ERCOT System security. ERCOT shall Dispatch the RMR Unit as early as possible once conditions are identified that require the use of the RMR Unit, as defined in Section 4.4.8, RMR Offers and the RMR Agreement.

(d) Each RMR Unit must meet technical requirements specified in Section 8.1.2.1, Ancillary Service Qualification and Testing.

(e) The "Minimum Agreement Period" is the 180-day period from November 1 through April 30. ERCOT may execute RMR Agreements for the Minimum Agreement Period or for a term of one year, with one exception. ERCOT may execute an RMR Agreement for a term longer than 12 months if the Generation Entity must make a significant capital expenditure to meet environmental regulations or to ensure availability to continue operating the RMR Unit so as to make an RMR Agreement in excess of 12 months appropriate, in ERCOT's opinion. The term of a multi-year RMR Agreement must take into account the appropriate RMR exit strategy discussed in Section 3.14.1.4, Exit Strategy from an RMR Agreement. The RMR standard Agreement is included in Section 22, Attachment B, Standard Form Reliability Must Run Agreement.

(f) A Generation Resource is eligible for RMR status based on criteria established by ERCOT indicating its operation is necessary to support ERCOT System reliability according to the Operating Guides. A combined-cycle generation facility must be treated as a single unit for RMR purposes unless the combustion turbine and the steam turbine can operate separately. If the steam turbine and combustion turbine can operate separately, and the steam turbine is powered by waste heat from more than one combustion turbine, the combustion turbine accepted for RMR Service and a proportionate part of the steam turbine must be treated as a single unit for RMR purposes. If the combustion turbine accepted for RMR Service can operate separately from the steam turbine, and only the combustion turbine is accepted as an RMR Unit, the RMR energy price will be reduced by the value of the combustion turbine's waste heat calculated at the Fuel Index Price, except when the steam turbine is Off-Line. ERCOT shall post to the Market Information System (MIS) Secure Area the criteria upon which it evaluates whether an RMR Unit meets the test of operational necessity to support ERCOT System reliability within five Business Days of change.

(g) A Generation Entity cannot be compelled to enter into an RMR Agreement. A Generation Entity that owns a Generation Resource that is uneconomic to remain in service can voluntarily petition ERCOT for contracted RMR status by following the process in this subsection. ERCOT shall determine whether the Generation Resource is necessary for system reliability based on the criteria set forth in this Section.

(h) ERCOT must contract for the entire capacity of each RMR Unit.

(i) ERCOT shall post on the MIS Secure Area all information relative to the use of RMR Units including energy deployed monthly.

(j) The Generation Entity that owns the RMR Unit may not use the RMR Unit for:

(i) Participating in the bilateral energy market;

(ii) Self-providing of energy except for plant auxiliary Load obligations under the RMR Agreement; and

(iii) Providing of Ancillary Service to any Entity.

3.14.1.1 Notification of Suspension of Operations

Except for the occurrence of a Forced Outage, a Generation Entity must notify ERCOT in writing no less than 90 days before the date on which the Generation Entity intends to cease or suspend operation of a Generation Resource for a period of greater than 180 days by submitting a completed Part I of the Notification of Suspension of Operations (found in Section 22, Attachment I, Notification of Suspension of Operations). The Generation Entity may also complete Part II of the Notification and submit it along with Part I, or may wait to submit Part II until ERCOT makes an initial determination of the need for the Generation Resource as an RMR Unit. The Part I Notification must include the attestation of an officer of the Generation Entity that the Generation Resource is uneconomic to remain in service and will be unavailable for Dispatch by ERCOT for a period specified in the Notification. At least 60 days before the expiration of an existing RMR Agreement, the Generation Entity may apply to renew the RMR Agreement by submitting a new Notification (including both Part I and Part II).

3.14.1.2 ERCOT Evaluation

(1) Upon receipt of a Notification under Section 3.14.1.1, Notification of Suspension of Operation, ERCOT shall post the Notification on the MIS Secure Area and shall post all existing relevant studies and data and provide electronic notice to all Registered Market Participants of the Application and posting of the studies and data.

(2) Within 14 days after receiving the notice described in paragraph (1) above, unless otherwise notified by ERCOT that a shorter comment period is required, Market Participants may submit comments to ERCOT on whether the proposed RMR Unit meets the test of operational necessity to support ERCOT System reliability or whether the proposed RMR Unit should qualify for a multi-year RMR Agreement. ERCOT shall consider and post all submitted comments on the MIS Secure Area.

(3) Within 18 days after receiving the Notification, ERCOT shall make an initial determination of whether the Generating Resource is required to support ERCOT System reliability. ERCOT shall post this determination on the MIS Secure Area and notify the Generation Entity of the determination.

(4) Within 10 days after a determination by ERCOT that the Generating Resource is required to support ERCOT System reliability, the Generation Entity shall, if it has not already done so, complete and submit to ERCOT Part II of the Notification of Suspension of Operations (Section 22, Attachment I, Notification of Suspension of Operations). ERCOT shall post the Part II information on the MIS Secure Area. On the 11th day after the determination or on receipt of Part II of the Notification, whichever comes first, ERCOT and the Generation Entity shall begin good faith negotiations on an RMR Agreement. These negotiations shall include the budgeting process for Eligible Costs and for fuel costs as detailed in Section 3.14.1.8, Budgeting Eligible Costs, and Section 3.14.1.12, Budgeting Fuel Costs.

(5) Within 60 days after receiving the Part I Notification, ERCOT shall make a final assessment of whether the Generating Resource is required to support ERCOT System reliability. If ERCOT determines that the Generating Resource is required, and the RMR Agreement between ERCOT and the Generation Resource has not yet been finalized, good faith negotiations must continue. If ERCOT determines that the Generating Resource is not needed to support ERCOT System reliability, then the Generating Resource may cease or suspend operations according to the schedule in its Notification.

(6) If, after 90 days following ERCOT's receipt of the Part I Notification, either ERCOT has not informed the Generation Entity that the Generation Resource is not needed for ERCOT System reliability or both parties have not signed a RMR Agreement for a Generating Resource that ERCOT has determined to be required for ERCOT System reliability, then the Generation Entity may file a complaint with the PUCT under subsection (f)(1) of P.U.C. SUBST. R. 25.502, Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas.

(7) If, after 90 days following receipt of the Part I Notification, ERCOT and the Generation Entity have not finalized an RMR Agreement for a Generation Resource that ERCOT has determined to be required for ERCOT System reliability, then the Generating Entity shall maintain that Generation Resource(s) so that it is available for RUC commitment until no longer required to do so under P.U.C. SUBST. R. 25.502(f)(2).

3.14.1.3 ERCOT Report to Board on Signed RMR Agreements

(1) After receiving a Notification of Suspension of Operations and conducting the analysis required by the Protocols and after the date on which it executes an RMR Agreement, ERCOT shall provide notice to the Board, at the next Board meeting after ERCOT has signed the RMR Agreement, that the following steps have been completed with respect to any RMR Agreement signed by ERCOT:

(a) The Generation Entity provided a complete and timely Notification of Suspension of Operations including a sworn attestation supporting its claim of pending plant closure;

(b) ERCOT received all the data requested from the applicant necessary to evaluate the need for and provisions of the RMR Agreement, that information was posted on the MIS Secure Area by ERCOT, as it became available to ERCOT and no later than before ERCOT signed the RMR Agreement;

(c) The signed RMR Agreement complies with the ERCOT Protocols;

(d) ERCOT evaluated:

(i) The reasonable alternatives to a specific RMR Agreement that exist and compared the alternatives against the feasibility, cost and reliability impacts of the signed RMR Agreement;

(ii) The timeframe in which ERCOT expects each unit to be needed for reliability; and

(iii) The specific type and scope of reliability concerns identified for each RMR Unit.

(2) ERCOT shall post on the MIS Secure Area, as they become available, unit-specific studies, reports, and data, by which ERCOT justified entering into the RMR Agreement.

3.14.1.4 Exit Strategy from an RMR Agreement

No later than 90 days after the execution of an RMR Agreement, ERCOT shall report to the Board and post on the MIS Secure Area a list of feasible alternatives that may, at a future time, be more cost-effective than the continued renewal of the existing RMR Agreement. Through the ERCOT System planning process, ERCOT shall develop a list of potential alternatives to the service provided by the RMR Unit. At a minimum, the list of potential alternatives that ERCOT must consider include, building new or expanding existing Transmission Facilities, installing voltage control devices, soliciting or buying by auction interruptible Load from Retail Electric Providers (REPs), or extending the existing RMR Agreement on an annual basis. If a cost-effective alternative to the service provided by the RMR Unit is identified, ERCOT shall provide a proposed timeline to study and/or implement the alternative.

3.14.1.5 Potential Alternatives to RMR Agreements

(1) ERCOT shall provide reasonably available information that would enable potential MRA Resources to assess the feasibility of submitting a proposal to provide a more cost-effective alternative to an RMR Unit through the regional planning process, including any known minimum technical requirements and/or operational characteristics required to eliminate the need for the RMR Unit. TAC shall review the output of the regional planning process and provide guidance prior to entering into an agreement with an MRA Resource (MRA Agreement).

(2) After the process identified in paragraph (1) above, ERCOT may negotiate a contract for an MRA Resource that:

(a) technically provides an acceptable solution to the reliability concern that would otherwise be solved by the RMR Unit(s);

(b) will provide a more cost-effective alternative to continued service by the RMR Unit (evaluated over the exit strategy period) provided, however, that no proposed MRA Resource will be considered if it does not provide at least $1 million in annual savings over the projected net annualized costs for the RMR Unit; and

(c) satisfies objective financial criteria to demonstrate that the seller is reasonably able to fulfill its performance obligations as determined by ERCOT.

(3) If the resulting MRA Agreement would result in significantly lower total costs (on a risk-adjusted basis) than continued service by the RMR Agreement, and otherwise meets the requirements of this subsection, ERCOT may sign the MRA Agreement. The term of the MRA Agreement must be limited to the time period until the cost-effective transmission alternative can be implemented.

(4) If the execution of an MRA Agreement would result in the foreclosure of other technically viable solutions (e.g., the RMR Unit that is being replaced by the MRA Agreement retires and is no longer available as an alternative to the MRA Agreement), the MRA Agreement shall include terms and conditions that limit the MRA Resource owner’s ability to withdraw or raise the price of the MRA Agreement in future years until a transmission solution can be implemented.

(5) For any MRA Agreement entered into by ERCOT, ERCOT shall annually update the list of feasible alternatives developed in Section 3.14.1.4, Exit Strategy from an RMR Agreement, and provide an update of that information to the TAC and the ERCOT Board.

3.14.1.6 Transmission System Upgrades Associated with an RMR and/or MRA Exit Strategy

This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) ERCOT and the Transmission Service Provider(s) (TSP(s)) responsible for constructing upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall coordinate construction clearances necessary to allow timely completion of all planned Transmission Facilities upgrades.

(b) The TSP(s) responsible for constructing upgrades to the Transmission Facilities that are part of an RMR or MRA exit strategy shall establish and send to ERCOT estimated Outage information, including completion dates and associated model information to ERCOT per Section 3.1.4, Communications Regarding Resource and Transmission Facilities Outages. For purposes of this Section, a Transmission Facility upgrade will be considered initiated upon the TSP authorizing any expenditures on the upgrade including, but not limited to, material procurement, right-of-way acquisition, and regulatory approvals.

(c) Upon initiation of the project, the TSP(s) responsible for constructing upgrades relating to the Transmission Facilities that are part of an RMR or MRA exit strategy shall provide to ERCOT monthly updates of the project's status, noting any acceleration or delay in planned completion date. ERCOT shall report this data through the MIS as described in Section 12.2, ERCOT Responsibilities. Within 60 days of the completion date shown in the Notice provided per Section 3.1.4, for the Transmission Facilities upgrades, the TSP will coordinate more timely updates if the timeline changes significantly.

(d) Within ten Business Days after completion of the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy, ERCOT shall publish a Market Notice of such completion and the effective date of termination of the associated RMR or MRA Agreement.

3.14.1.7 RMR or MRA Contract Termination

(1) This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(2) Once a suitable RMR or MRA exit strategy has been developed as defined in Section 3.14.1.4, Exit Strategy from an RMR Agreement, and the strategy has been approved by the ERCOT Board and the affected TSP(s), the TSP(s) responsible for the Transmission Facilities upgrades, when requested by ERCOT, shall submit to ERCOT:

(a) A preliminary construction outage schedule necessary to complete the Transmission Facilities upgrades. Submissions, changes, approvals, rejections, and withdrawals regarding the preliminary construction outage schedule shall be processed through the ERCOT Outage Scheduler on the ERCOT MIS. Such construction outage schedule shall be updated monthly; or

(b) A CCN application timeline for projects requiring such PUCT certification. Once a CCN has been granted by the PUCT, the TSP(s) shall be required to meet the requirements in item (a) above.

(3) ERCOT will review and approve or reject each construction outage schedule as provided in accordance with procedures developed by ERCOT in compliance with Protocol Section 3.1, Outage Coordination.

(4) The TSP(s) responsible for the Transmission Facilities upgrades that are part of an RMR or MRA exit strategy shall provide to ERCOT a project status and an estimated project completion date within five Business Days of ERCOT's request.

(5) If ERCOT determines that a mutually agreeable preliminary construction outage schedule can be accommodated during the fall, winter, or spring, ERCOT and the TSP shall collaborate to determine if the 90 day termination notice for the RMR and/or MRA can be issued as soon after the summer load season of the preceding year as possible and publish a Market Notice of these terminations. ERCOT and the TSP may give

consideration to the risk of the decision to terminate the RMR and/or MRA Agreement and any options, such as Remedial Action Plans and/or Mitigation Plans that could be used to mitigate transmission construction delays.

3.14.1.8 RMR and/or MRA Contract Extension

This section applies only to RMR exit strategies corresponding to specific RMR or MRA Agreements that have not been terminated.

(a) Forty-five days prior to the termination date of an existing RMR or MRA Agreement, pursuant to the 90-day termination notice as described in paragraph A(2) of Section 3, Term and Termination, of Section 22F, Standard Form Reliability Must-Run Agreement, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) necessary to allow termination of an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that a delay in the termination date of the existing RMR or MRA Agreement is necessary to allow completion of the Transmission Facilities upgrade(s), it shall provide written notice to the Resource Entity that owns the RMR Unit or MRA Resource of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned termination date.

(b) Forty-five days prior to the expiration date of an existing RMR or MRA Agreement for which the Generation Entity has applied for renewal, ERCOT shall assess the likelihood of completion of the Transmission Facilities upgrade project(s) necessary to eliminate the reliability need for a Resource with an existing RMR or MRA Agreement based on the updates of project status provided by the TSP(s). If ERCOT determines that an extension of the existing RMR or MRA Agreement of no more than 90 days would allow completion of the Transmission Facilities upgrade(s), it shall provide written notice to the Resource Entity that owns the RMR Unit or MRA Resource of its intent to execute an extension to the existing RMR or MRA Agreement no later than 30 days prior to the planned expiration date.

(c) ERCOT may extend the existing RMR or MRA Agreement as necessary to allow completion of the Transmission Facilities upgrade(s), but in no event shall the extension last more than 90 days from the termination or expiration date of the existing RMR or MRA Agreement.

(d) Forty-five days prior to the end of the period for which the existing RMR or MRA Agreement has been extended, ERCOT shall assess whether the transmission upgrades are likely to be completed. If ERCOT determines that the upgrades are not likely to be completed, ERCOT shall enter into negotiations with the Resource Entity that owns the RMR or MRA Resource to negotiate a new RMR or MRA Agreement to allow completion of the planned transmission upgrades.

3.14.1.9 Mothballed Generation Resource Time to Service Updates

By April 1st of each year and when material changes occur, every Generation Entity that owns or controls a Mothballed Generation Resource or an RMR Unit with an approved exit strategy shall report to ERCOT, on a unit-specific basis, the estimated lead time required for each Resource to be capable of returning to service and, in percentage terms, report probable generation capacity from each Resource that the Generation Entity expects to return to service in each Season of each of the next five years.

3.14.1.10 Eligible Costs

"Eligible Costs" are costs that would be incurred by the RMR Unit owner to provide the RMR Service, excluding fuel costs, above the costs, excluding fuel costs, the RMR Unit would have incurred anyway had it been mothballed or shut down.

(a) Examples of Eligible Costs include the following to the extent they each meet the standard for eligibility:

(i) Labor to operate the RMR Unit during the term of the RMR Agreement;

(ii) Materials and supplies consumed or used in operation of the RMR Unit during the term of the RMR Agreement;

(iii) Services necessary to operate the RMR Unit during the term of the RMR Agreement;

(iv) Costs associated with emissions credits used as a direct result of operation of the RMR Unit under direction from ERCOT, or emissions reduction equipment as may be required according to terms of the RMR Agreement;

(v) Costs associated with maintenance:

(A) Due to required equipment maintenance;

(B) Due to replacement to alleviate unsafe operating conditions;

(C) Due to regulatory requirements, with compliance dates during the term of the RMR Agreement (any such compliance dates and requirements shall be explicitly defined in the RMR Agreement); or

(D) To ensure the ability to operate the RMR Unit consistent with Good Utility Practice;

(vi) Reservation and transportation costs associated with firm fuel supplies not recovered under Section 6.6.6.2, RMR Payment for Energy;

(vii) Property taxes and other taxes attributable to continuing to operate the RMR Unit during the term of the RMR Agreement; and

(viii) Nodal implementation surcharges.

(b) Examples of costs not included as Eligible Costs are:

(i) Depreciation expense, return on equity, and debt and interest costs;

(ii) Property taxes and other taxes not attributable to continuing to operate the RMR Unit;

(iii) Income taxes of the RMR Unit owner or operator;

(iv) Labor costs associated with other, non-RMR Generation Resources at the same facility; and

(v) Any other costs the Generation Entity that owns the RMR Unit would have incurred even if the RMR Unit had been mothballed or shutdown.

3.14.1.11 Budgeting Eligible Costs

(1) The owner of the RMR Unit shall provide good faith detailed estimates of its Eligible Costs to ERCOT as part of the RMR Agreement negotiation process. ERCOT shall review and approve the budget and use these figures as the basis for Initial Settlement for RMR Service. Actual Eligible Costs incurred by the RMR Unit will be used for subsequent Final, Resettlement, or True-Up Settlements as agreed upon in Section 6.6.6, Reliability Must-Run Settlement.

(2) The Eligible Cost budgeting process is as follows:

(a) The RMR Unit owner shall supply ERCOT a preliminary Eligible Cost budget for the 12-month period starting with the anticipated effective date of the RMR Agreement. The budget will include Eligible Costs categorized in terms of:

(i) Base Cost of Operations, which includes Eligible Costs that are independent of the levels of operation, Outages and non-Outage maintenance;

(ii) Outage Maintenance Cost, which includes Eligible Costs attributable to Planned or Maintenance Outages and/or inspections occurring during the term of the RMR Agreement. Maintenance alternatives available during any Planned or Maintenance Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT's selection process;

(iii) Non-Outage Maintenance Cost, which includes non-recurring Eligible Costs that are independent of a particular scheduled Outage. Non-Outage maintenance alternatives available during any scheduled Outage must be presented to ERCOT for determination of the alternative to be performed and paid for under the RMR Agreement. The RMR Unit owner must present ERCOT with a budget for each option, benefits of each alternative, unit availability impact associated with not performing each alternative, and a recommendation to facilitate ERCOT's selection process;

(iv) Other budget items means Eligible Costs not clearly identifiable in the previous three categories including:

(A) Environmental emission credit consumption (or purchase as explicitly defined under the RMR Agreement, to operate the unit) includes the opportunity cost for using emission credits through the combustion of fuel feedstock by the RMR Unit. Costs must be based on verifiable market data as supplied by the RMR Unit owner; and

(B) "Compliance Costs," which includes foreseeable costs to comply with regulations, Federal or state that have a compliance deadline that occurs during the term of the RMR Agreement.

(b) Thirty days after receipt of the preliminary Eligible Costs budget, ERCOT shall notify the RMR Unit owner of its selections under the alternatives provided in the preliminary budget. The RMR Unit owner and ERCOT shall set the Target Availability consistent with the options presented to and selected by during the budgeting process. The "Target Availability" shall be determined by taking into account a negotiated amount of predicted Forced Outages and Planned Outages identified during the budgeting process.

3.14.1.12 Reporting Actual Eligible Cost

The RMR Unit owner shall provide ERCOT with actual Eligible Costs on a monthly basis in a level of detail sufficient for ERCOT to verify that all Eligible Costs are actual and appropriate. Actual cost data must be submitted on time by the Generation Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month 'x' must be submitted by the 20th of the month following month 'x'. To be considered timely for the true-up, actual cost data for month 'x' must be submitted 30 days prior to the publishing date of the True-Up Settlement Statement for the first day in month 'x'. Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the Qualified Scheduling Entity (QSE) representing an RMR unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. ERCOT shall post on the Public MIS any such request and response thereto. In the event, that actual cost data is not submitted in accordance with the calendar or approved deviation for the true-up, then the cost for the portion of eligible cost that has not been submitted is deemed to be zero.

3.14.1.13 Incentive Factor

(1) Subject to the reductions described in items (2) and (3), the Incentive Factor for RMR Agreements is equal to 10% of the actual Eligible Costs excluding fuel costs incurred by the RMR Unit. The Incentive Factor for RMR Agreements is not applied to capital expenditures as described in Section 3.14.1, Reliability Must Run, nor is the Incentive Factor applied to nodal implementation surcharges. The Incentive Factor shall never be less than zero.

(2) The Incentive Factor payment shall be reduced if the RMR Unit fails to perform to the contracted capacity during a Capacity Test as described in the RMR Agreement. The reduction will be linear, with a two percent reduction in the Incentive Factor payment for every one percent of reduced Capacity.

(3) The Incentive Factor payment shall be reduced if the "Hourly Rolling Equivalent Availability Factor" of the RMR Unit is less than the Target Availability (i.e. the "Actual Availability", as defined below, is less than the Target Availability). The reduction will be linear; with a two percent reduction in the Incentive Factor payment for every one percent of the Hourly Rolling Equivalent Availability Factor is less than the Target Availability stated in the RMR Agreement. The RMR Unit's Actual Availability shall be calculated on an hourly rolling six-month average basis by dividing the number of hours that the RMR Unit was available according to its final COP for each hour of the previous 4380 hours by 4380. If less than 4380 hours have elapsed since the start of the RMR Agreement ("Elapsed Time"), then, for each hour that Elapsed Time is less than 4380, that hour shall be considered as if the RMR Unit was available.

3.14.1.14 Major Equipment Modifications

During the term of an RMR Agreement, in the event that major equipment modifications are required in order for the RMR Unit to provide RMR Service (such as installation of environmental control equipment), ERCOT and the RMR Unit owner shall negotiate in good faith concerning changes to the terms of the RMR Agreement.

3.14.1.15 Budgeting Fuel Costs

(1) The RMR Unit owner shall supply ERCOT a preliminary fuel cost budget for the 12-month period starting with the anticipated effective date of the RMR Agreement. The budget must include information pertaining to the cost of the fuel feedstock, including where appropriate transportation costs and terms, as well as fuel storage costs and terms, and any other fuel contract provisions (e.g. "take or pay" provisions) that may impact the

cost of all fuels anticipated to be used by the RMR Unit over the life of the RMR Agreement and must include fuel costs categorized in terms of:

(a) primary fuel; and

(b) secondary fuel.

(2) The RMR Unit owner shall provide good faith estimates of the RMR Unit input/output curve to ERCOT in its application for an RMR Agreement. Based on production figures provided to the RMR Unit owner by ERCOT, the RMR Unit owner shall also provide ERCOT fuel supply options available for the RMR Unit. For each option, RMR Unit owner shall detail the associated impacts on the fuel and non-fuel budgets and on the availability of the unit. No less than 30 days after the receipt of the fuel supply options, ERCOT shall notify the RMR Unit owner of its fuel supply option selection.

3.14.1.16 Reporting Actual Eligible Costs

(1) The RMR Unit owner shall provide ERCOT with actual fuel costs on a monthly basis for the RMR Unit in a level of detail sufficient for ERCOT to verify that all fuel costs are actual and appropriate. The estimated fuel payments may include a fuel adder to better approximate expected actual fuel costs. ERCOT shall perform a true-up of the estimated fuel costs using the submitted and verified actual fuel costs for the RMR Unit. Actual cost data must be submitted on time by the Generation Entity for the RMR Unit and then verified by ERCOT so the actual cost data can be reflected in the True-Up Settlement Statement. To be considered timely for the final, actual cost data for month ‘x’ must be submitted by the 20th of the month following month ‘x’. To be considered timely for the true-up, actual cost data for month ‘x’ must be submitted 30 days prior to the publishing date of the True-Up Settlement Statement for the first day in month ‘x’. Any deviation in filing actual cost data in accordance with this calendar must be requested of ERCOT, by the QSE representing an RMR unit. Such request for deviation shall contain the reason for the inability to meet the calendar and an expected date that the cost data will be provided to ERCOT. At its discretion ERCOT may choose to honor such a request. ERCOT shall post on the Public MIS any such request and response thereto. In the event, that actual cost data is not submitted in accordance with the calendar or approved deviation for the true-up, then the cost for the portion of Eligible Cost that has not been submitted is deemed to be zero.

(2) Actual fuel costs must be appropriate actual costs attributable to ERCOT’s scheduling and/or deployment of the RMR Unit. Actual fuel costs may include cost of fuel (including the cost of exceeding swing gas contract limits, additional gas demand costs set by fuel supply, or transportation contracts); demand fees, imbalance penalties, transportation charges, and cash out premiums.

3.14.2 Black Start

(1) Each Generation Resource providing Black Start Service must meet the requirements specified in NERC policy and the Operating Guides.

(2) Each Generation Resource providing Black Start Service must meet technical requirements specified in Section 8.1.2, QSE Ancillary Service Performance Standards, and Section 8.1.2.1, Ancillary Service Qualification and Testing.

(3) Bids for Black Start Service are due on or before June 1st of each year. Bids must be evaluated based on evaluation criteria attached as an appendix to the request for bids and contracted by December 31st for the following calendar year. ERCOT shall ensure Black Start Services are arranged, provided, and deployed as necessary to reenergize the ERCOT System following a total or partial system blackout.

(4) ERCOT shall schedule random testing or simulation, or both, to verify Black Start Service is operable according to the ERCOT System restoration plan. Testing and verification must be done under established qualification criteria.

(5) QSEs representing Generation Resources contracting for Black Start Services shall participate in training and restoration drills coordinated by ERCOT.

(6) ERCOT shall periodically conduct system restoration seminars for all TSPs, Distribution Service Providers (DSPs), QSEs, Resource Entities and other Market Participants.

(7) ERCOT shall periodically determine and review the location and number of Black Start Resources required, as well as any special transmission or voice communication needs required. ERCOT and providers of this service shall meet the requirements as specified in the ERCOT Operating Guides and in NERC policy.

3.14.3 Emergency Interruptible Load Service (EILS)

(1) ERCOT shall procure EILS for EILS Contract Periods. The standing EILS Contract Periods are as follows:

(a) June through September;

(b) October through January; and

(c) February through May.

(2) ERCOT may restructure EILS Contract Periods in order to facilitate additional Load participation in EILS. ERCOT shall provide Notice of any changes to the standing EILS Contract Periods no less than 90 days prior to the start date of that EILS Contract Period.

(3) ERCOT will solicit offers to provide EILS prior to each EILS Contract Period. ERCOT may procure additional EILS at any time.

(4) EILS offers may be submitted to ERCOT only by QSEs capable of receiving Verbal Dispatch Instructions (VDIs) on behalf of represented EILS Loads. A QSE may submit offers on behalf of multiple EILS Loads for any EILS Contract Period.

(5) ERCOT shall solicit EILS offers. QSEs on behalf of EILS Load may submit offers for one or more EILS Time Periods within a Contract Period. An EILS offer is specific to an EILS Time Period. In submitting an offer, a QSE and the EILS Load are committing to provide EILS for that Time Period if selected.

(6) The minimum amount of EILS that may be offered in an offer to ERCOT is one megawatt (MW). EILS Loads may be aggregated to reach the one MW offer requirement.

(7) An offer to provide EILS shall include:

(a) The name of the QSE representing the EILS Load;

(b) The name of the Entity supplying the EILS Loads;

(c) A description of the Load(s) that will provide EILS if selected, including name(s) and Electric Service Identifier(s) (ESI ID(s));

(d) The EILS Time Period for which the offer is submitted;

(e) A dollars per MW price for the capacity offer unless the offer is for EILS Self-Provision;

(f) The quantity of capacity for which the offer price is effective, expressed in whole number MWs;

(g) The minimum base Load, in MW, for each ESI ID in the EILS Load, defined as that level of Load the EILS Load is unwilling to interrupt in an EILS deployment event;

(h) For EILS Loads that are not metered by a dedicated ESI ID in a competitive choice area of the ERCOT Region, including those situated in territories served by Non-Opt-In Entities (NOIEs) or within Private Use Networks, the most recently available 12 months of Interval Data Recorder (IDR) data in a format specified by ERCOT;

(i) QSEs opting for EILS Self-Provision must provide ERCOT with the maximum amount of capacity they plan to provide through this option before ERCOT begins to accept EILS offers;

(j) A QSE opting for EILS Self-Provision may also offer separate capacity into EILS in the form of a priced offer in the same manner as any other QSE; and

(k) Affirmation that the capacity being offered into EILS is not capacity that is separately obligated to respond during an Emergency Electric Curtailment Plan (EECP) event, and receiving a separate reservation payment for such obligation, occurring in the contracted EILS Time Period.

(8) QSEs may self-provide EILS. Self-providing QSEs must adhere to the following steps for offering EILS in an EILS Contract Period:

(a) A QSE electing to self-provide part or all of its EILS obligation for an EILS Contract Period shall provide ERCOT with the following, while adhering to a schedule published by ERCOT:

(i) The maximum MW of capacity it is willing to offer through EILS Self-Provision, per EILS Time Period; and

(ii) A Proxy Load Ratio Share specific to the Time Period. "Proxy Load Ratio Share" shall be a number between zero and one and determined by the self-providing QSE to represent its estimate of its final Load Ratio Share to be used in EILS Settlement.

(b) After receiving EILS Self-Provision information, ERCOT will award offers for additional MWs of EILS capacity such that EILS capacity procured through EILS offers and the combined maximum MW capacity for EILS Self-Provision do not exceed 1,000 MW.

(c) If the total amount of EILS capacity procured through offers and EILS Self-Provision equals 1,000 MW, a QSE shall not change its EILS Self-Provision capacity obligation.

(d) If the total amount of EILS capacity procured through offers and EILS Self-Provision is less than 1,000 MW, ERCOT shall provide QSEs offering EILS Self-Provision their adjusted estimated obligation based on their Proxy Load Ratio Shares. A QSE may then reduce its EILS Self-Provision capacity to a number no lower than the lowest number represented in the following three options:

(i) **Option 1 —** The capacity of MW procured by ERCOT through offers divided by one minus the sum of EILS Self-Provision Proxy Load Ratio Shares multiplied by the QSE's Proxy Load Ratio Share, as expressed in the following formula:

$$\textbf{(Total\_OFFERProc}_{\,qc(tp)}\ \textbf{/ (1-}\sum\textbf{ProxSPLRS}_{\,qc(tp)}\textbf{))*ProxSPLRS}_{\,qc(tp)}$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	QSE
c	None	EILS Contract Period

tp	None	Hours in an EILS Time Period
Total_OFFERProc $_{qc(tp)}$	MW	Total contracted capacity for an EILS Load for the EILS Time Period
ProxSPLRS $_{qc(tp)}$	%	The value reported by each QSE of its estimated Load Ratio Share for EILS for the EILS Time Period

(ii) **Option 2 —** The sum of the capacity procured by ERCOT and the capacity self-provided multiplied by the QSE's Proxy Load Ratio Share, as expressed in the following formula:

$$\textbf{(Total\_OFFERProc}_{\ qc(tp)} + \sum \textbf{OfferedSP}_{\ qc(tp)}\textbf{)} * \textbf{ProxSPLRS}_{\ qc(tp)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
q	None	QSE
c	None	EILS Contract Period
tp	None	Hours in an EILS Time Period
Total_OFFERProc $_{qc(tp)}$	MW	Total contracted capacity for an EILS Load for the EILS Time Period
OfferedSP $_{qc(tp)}$	MW	The capacity offered by a QSE for EILS Self-Provision for the EILS Time Period, as communicated to ERCOT prior to ERCOT procuring competitive EILS offers.
ProxSPLRS $_{qc(tp)}$	%	The value reported by each QSE of its estimated Load Ratio Share for EILS for the EILS Time Period

(iii) **Option 3 —** The QSE's declared maximum MW offer self-provided capacity.

(e) A QSE with reduced EILS Self-Provision capacity may reduce the commitment(s) of specific EILS Loads by providing Notification to ERCOT. Such Notification must be received by ERCOT within two Business Days following ERCOT's Notification to the QSE of its reduced obligation.

(f) If a QSE reduces its EILS commitment according to these procedures, it will not be obligated to pay EILS charges so long as the amount of its EILS Self-Provision capacity remains equal to or greater than its final Load Ratio Share of the total EILS capacity procured through offers and EILS Self-Provision, as described in item (1) of Section 6.6.11, Emergency Interruptible Load Service (EILS) Capacity, and so long as all self-provided EILS Loads meet their availability and performance obligations as described in Section 8.1.3.1, Performance Criteria for EILS Loads.

(9) ERCOT shall not procure more than $50 million of EILS in any 12 month period beginning on February 1st and ending on January 31st ("EILS Cap"). ERCOT may determine cost limits for each EILS Contract Period in order to ensure that the EILS Cap is not exceeded. In order to minimize the cost of EILS, ERCOT may reject any offer it determines to be unreasonable or outside the parameters of an acceptable offer. ERCOT shall establish a written process for determining the cost limits for each EILS Contract Period and for the reasonableness of offers.

(10) ERCOT shall reduce the EILS Cap by the value of the amount of EILS Self-Provision. ERCOT shall value EILS Self-Provision at the weighted average cost per MW of the EILS procured multiplied by the total MW of EILS Self-Provision during each relevant EILS Time Period and EILS Contract Period.

(11) The maximum amount of EILS for which ERCOT may contract in an EILS Contract Period is 1,000 MW for each EILS Time Period.

(12) ERCOT shall evaluate each offer to determine the actual capacity an EILS Load is capable of providing and may limit any award to that EILS Load based on the results of the evaluation.

(13) ERCOT shall select EILS Loads for each EILS Time Period to serve during an EILS Contract Period based upon least cost offer per MW of capacity offered based upon the payment as offered for selected EILS Loads; provided that ERCOT may consider geographic location and its effect on zonal or local congestion in selecting EILS Load. ERCOT may prorate awards when there are more MWs available at a given price than ERCOT can procure, if acceptable to the offering QSE. An EILS offer may declare a minimum amount of MW that the EILS Load is willing to provide and, if proration would result in an award below that amount, the offer will be excluded from the EILS procured.

(14) QSEs representing selected EILS Loads, except for Load designated for EILS Self-Provision, will be entitled to payment as offered, subject to adjustment, pursuant to these Protocols. Deployment of EILS Loads will not result in additional payments other than any Load imbalance payments received.

(15) QSEs representing EILS Loads selected to provide EILS shall execute a Standard Form EILS Agreement, as provided in Section 22, Attachment K, Standard Form Emergency Interruptible Load Service (EILS) Agreement, for each committed EILS Time Period and EILS Contract Period.

(16) An EILS Load shall be subject to a maximum of two Dispatch Instructions per EILS Contract Period. Additionally, an EILS Load shall be subject to a maximum of eight hours of Dispatch Instructions per EILS Contract Period, unless an EILS deployment is still in effect when the eighth hour lapses (in which case the EILS Load must follow the Dispatch Instruction until ERCOT releases the EILS Load).

(17) Unless ERCOT has received a notice of unavailability in a format prescribed by ERCOT, ERCOT shall assume that such a contracted EILS Load is fully available for receiving Dispatch Instructions.

(18) EILS Loads shall meet the following technical requirements:

(a) Each EILS Load must have an ESI ID or other unique service identifier, as defined by ERCOT. Each individual EILS Load must have an installed IDR meter or equivalent, subject to ERCOT approval, dedicated to the Load providing EILS. ERCOT shall analyze 15-minute interval meter data for each EILS Load for purposes of offer analysis, availability and performance measurement. EILS Loads behind an NOIE meter point shall arrange, preferably with the NOIE Transmission Service Provider (TSP), to provide ERCOT with 15-minute interval meter data subject to ERCOT's specifications and approval. EILS Loads behind a Private Use Network's Settlement Meter point shall provide ERCOT 15-minute interval meter data subject to ERCOT's specifications and approval. Notwithstanding the aforementioned, ERCOT may accept offers or self-provision offers from QSEs representing non-IDR metered aggregated EILS Loads if the QSE submits and ERCOT approves a statistically valid alternative to universal IDR metering for measurement and verification consistent with industry best practices. ERCOT shall publish guidelines and schedules for submittal of such alternatives.

(b) An EILS Load must be capable of reducing its Load by its contracted capacity relevant to its assigned baseline methodology within ten minutes of an ERCOT Dispatch Instruction to its QSE and must be able to maintain such reduced capacity level for the entire period of the Dispatch Instruction and shall not return to normal operations until released to do so by ERCOT. The ERCOT EILS Dispatch Instruction to an NOIE opting for EILS Self-Provision that is also dynamically scheduling shall be considered an instructed deviation so the NOIE is not penalized for keeping Generation Resources On-Line.

(c) Any QSE representing an EILS Load must be capable of communicating with its EILS Loads within the prescribed time constraints for deployment of EILS.

(d) Committed EILS Loads are responsible for communicating any material changes in availability status to the QSE representing the EILS Load and to ERCOT, irrespective of whether the change in availability is scheduled with ERCOT as described in paragraph (5) of Section 8.1.3.1, Performance Criteria for EILS Loads.

(e) EILS Loads deployed for EILS must be able to return to their contracted operating level for providing EILS for any committed hours within ten hours following a release Dispatch Instruction.

(f) EILS Loads and their QSEs are subject to qualification based on ERCOT's evaluation of their historic meter data and, if applicable, their historic performance in providing other comparable ERCOT services. EILS Loads and their QSEs are subject to performance and testing requirements as described in Section 8.1.3, Emergency Interruptible Load Service (EILS) Performance and Testing.

(g) EILS Loads are not subject to the modeling, telemetry and Resource plan requirements of other Resources.

(19) The contracted capacity of EILS Loads may not be used to provide Ancillary Services during the contracted EILS Time Period of the contracted EILS Contract Period. Nothing herein shall be construed to limit passive (voluntary) Load response, provided the EILS performance requirements as described in Section 8.1.3.1, Performance Criteria for EILS Loads, are met.

(20) ERCOT will review the effectiveness and benefits of EILS every 12 months from the start of the program and report its findings to TAC.

(21) Within ten days of the announcement of awards for EILS for an upcoming Contract Period, ERCOT shall post on the MIS Public Area the number of MW procured per EILS Time Period, the number of EILS Loads selected, and the projected total cost of EILS for that Contract Period.

3.15 Voltage Support

(1) ERCOT in coordination with the TSPs shall conduct studies to determine the normally desired predetermined distribution of desired nominal voltage set points across the ERCOT System Voltage Profile for all Electrical Buses used for Voltage Support in the ERCOT System and shall post all Voltage Profiles on the MIS Secure Area. ERCOT may temporarily modify its requirements based on Current System Conditions. ERCOT shall determine the amount of Voltage Support Service needed to provide sufficient reactive capacity in appropriate locations to provide ERCOT System security as specified in the ERCOT Operating Guides.

(2) All Generation Resources (including self-serve generating units) that have a gross generating unit rating greater than 20 MVA or those units connected to the same transmission Electrical Bus that have gross generating unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service.

(3) Generation Resources required to provide VSS must be capable of producing a defined quantity of Reactive Power (MVars) at a .95 power factor at the Resource’s maximum rated real power capability (MWs) to maintain a Voltage Profile established by ERCOT. This quantity of Reactive Power is the Unit Reactive Limit (URL).

(4) Generation Resources required to provide VSS whose installations initially began operations on or after September 1, 1999, except as noted below, must have and maintain a URL which has an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the generating unit's maximum net power to be supplied to the transmission grid and at the transmission system Voltage Profile established by ERCOT, and both measured at the point of interconnection to the TSP.

(5) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the URL as stated above, must maintain a URL that is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and criteria as described in the ERCOT Operating Guides.

(6) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the URL as stated above, must maintain a URL that is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and criteria described in the ERCOT Operating Guides.

(7) Upon request to, and with the approval of ERCOT, multiple generating units connected to the same transmission Electrical Bus may be treated as a single generating unit for the purposes of these URL requirements only.

(8) Upon submission by a Generation Resource required to provide VSS to ERCOT of a specific proposal for requirements to substitute for these URL requirements, ERCOT shall either approve such alternative requirements or provide the submitter an explanation of its objections to the proposal. Alternative requirements may include supplying additional static and/or dynamic Reactive Power capability as necessary to meet the area's Reactive Power requirements.

(9) An induction generator may elect to make a contribution in aide of construction in lieu of meeting the installed capacity VSS requirements contained herein. In order to comply with the VSS requirements under this Subsection, the generator must make payment to the interconnecting TSP under its Standard Generation Interconnection Agreement in a manner similar to that used to collect payments for the direct assignment of interconnection Facilities under applicable PUCT rules. The level of payment shall reflect the cost to the TSP of procuring, installing, operating, and maintaining any Reactive Power equipment required to replace the Reactive Power capability that otherwise would be necessary to interconnect the generator. In order for this Subsection to be effective for VSS compliance, the TSPs shall certify to ERCOT that the induction generator has complied with these requirements.

(10) For Generation Resources required to provide VSS, no unit equipment replacement or modification may reduce the capability of the unit below the requirements to be met by that unit prior to the replacement or modification, unless specifically approved by ERCOT.

(11) Generation Resources required to provide VSS may not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

3.15.1 ERCOT Responsibilities Related to Voltage Support

(1) ERCOT, in coordination with the TSPs, shall establish, and update as necessary, Voltage Profiles at points of interconnection of Generation Resources required to provide VSS to maintain system voltages within established limits.

(2) ERCOT shall communicate to the QSE and TSPs the desired voltage at the point of generation interconnection by providing Voltage Profiles.

(3) ERCOT, in coordination with TSPs, shall deploy static Reactive Power Resources as required to continuously maintain dynamic Reactive Reserves from QSEs, both leading and lagging, adequate to meet ERCOT System requirements. Reactive Reserve is the reactive capability needed to meet sudden loss of generation, Load or transmission capacity and maintain voltage within desired limits.

(4) For any Market Participant's failure to meet the Reactive Power voltage control requirements of these Protocols, ERCOT shall notify the Market Participant in writing of such failure and, upon a request from the Market Participant, explain whether and why the failure must be corrected.

(5) ERCOT shall notify all affected TSPs of any alternative requirements it approves.

(6) Annually, ERCOT shall review DSP power factors using the actual summer Load and power factor information included in the annual Load data request to assess whether DSPs comply with the requirements of this subsection. At times selected by ERCOT, ERCOT shall require manual power factor measurement at substations and points of interconnection that do not have power factor metering. ERCOT shall try to provide DSPs sufficient notice to perform the manual measurements. ERCOT may not request more than four measurements per calendar year for each DSP substation or point of interconnection where power factor measurements are not available.

(7) If actual conditions indicate probable non-compliance of TSPs and DSPs with the requirements to provide voltage support, ERCOT shall require power factor measurements at the time of its choice while providing sufficient notice to perform the measurements.

(8) ERCOT shall investigate claims of TSP and DSP alleged non-compliance with Voltage Support requirements. The ERCOT investigator shall advise ERCOT and TSP planning and operating staffs of the results of such investigations.

3.15.2 TSP and DSP Responsibilities Related to Voltage Support

Each TSP, DSP, and "Private Use Network" shall meet the requirements specified in this subsection, or at their option, may meet alternative requirements specifically approved by ERCOT. A "Private Use Network" is an electric network connected to the ERCOT Transmission Grid that contains load that is not directly metered by ERCOT (i.e., load that is typically netted with internal generation). Such alternative requirements may include requirements for aggregated groups of facilities.

(a) Sufficient static Reactive Power capability shall be installed by a DSP or a Private Use Network not subject to a TSP or DSP tariff in substations and on the distribution voltage system to maintain at least a 0.97 lagging power factor for the maximum net active power supplied from a substation transformer at its distribution voltage terminals to the distribution voltage system. In those cases where a Private Use Network's power factor is established and governed by a TSP or DSP tariff, the TSP or DSP and Private Use Network owner shall ensure that the Private Use Network meets the requirements as defined and measured in the applicable tariff. For any substation transformer serving multiple DSPs, this power factor requirement shall be applied to each DSP individually for its portion of the total Load served.

(b) DSP substations whose annual peak Load has exceeded 10 MW shall have and maintain Watt/VAR metering sufficient to monitor compliance; otherwise, DSPs are not required to install additional metering to determine compliance.

(c) Assuming optimal use of all other required installed Reactive Power capability, ERCOT Regional Planning Groups or Transmission Planning shall determine and demonstrate the need for any additional static and/or dynamic Reactive Power capability necessary to ensure compliance with the ERCOT Planning Criteria, and ERCOT Transmission Planning shall establish responsibility for any associated facility additions among ERCOT TSPs.

(d) For monitoring of compliance of the TSP's planned facilities to the ERCOT Planning Criteria performance requirements, a self-certification process with random audits (similar to compliance to NERC Planning Standards), in conjunction with work performed in the ERCOT Regional Planning Groups, shall be used. Except under Force Majeure conditions, a TSP must maintain transmission system voltage within two percent of the scheduled voltage.

(e) All DSPs shall report any changes in their estimated net impact on ERCOT as part of the annual Load data assessment.

(f) As part of the annual Load data assessment, all Resource Entities owning Generation Resources shall provide an annual estimate of the highest potential affiliated MW and Mvar load (including any load netted with the generation output) and the highest potential MW and Mvar generation that could be experienced at the point of interconnection to the ERCOT Transmission Grid, based on the then current configuration (and the projected configuration if the configuration is going to change during the year) of the Generation Resource and any affiliated loads.

3.15.3 QSE Responsibilities Related to Voltage Support

(1) QSE Generation Resources required to provide VSS shall have and maintain Reactive Power capability at least equal to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides.

(2) QSE Generation Resources providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

(3) QSE Generation Resources providing VSS must meet technical requirements specified in Section 8.1.2.1, Ancillary Service Qualification and Testing, and the performance standards specified in Section 8.1.2, QSE Ancillary Service Performance Standards.

(4) Each QSE's Generation Resource providing VSS shall operate with the unit's Automatic Voltage Regulator (AVR) in the voltage control mode unless specifically directed to operate in manual mode by ERCOT, or when the unit is going On-Line or Off-Line or the QSE determines a need to operate in manual mode in the event of an Emergency Condition at the generating plant. Each QSE shall send to ERCOT via telemetry, the AVR and Power System Stabilizer (PSS) status of each Generation Resource providing VSS. For AVRs, an "On" status will indicate the AVR is on and set to regulate the Resource's terminal voltage in the voltage control mode, and an "Off" status will indicate the AVR is off or in a manual mode. Each QSE shall monitor the status of their regulators and stabilizers, and shall report abnormal status changes to ERCOT.

(5) Each QSE shall meet, within established tolerances, and respond to changes in the Voltage Profile established by ERCOT subject to the stated QSE Reactive Power and actual power operating characteristic limits and voltage limits.

(6) The reactive capability required must be maintained at all times that the Generation Resource is On-Line.

3.16 Standards for Determining Ancillary Service Quantities

(1) ERCOT shall comply with the requirements for determining Ancillary Service quantities as specified in these Protocols and the ERCOT Operating Guides.

(2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the minimum quantity requirements for each Ancillary Service needed for reliability, including the percentage of Load Resources excluding Controllable Load Resources, the percentage of DC Tie, and the percentage of Controllable load Resources allowed to provide Responsive Reserve Service (RRS) calculated on a monthly basis.

(3) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements and the monthly percentage of Load Resources, Controllable Load Resources and DC Ties allowed to provide RRS.

(4) If ERCOT determines a need for additional Ancillary Service Resources under these Protocols or the ERCOT Operating Guides, after an Ancillary Service Plan for a specified day has been posted, ERCOT shall inform the market by posting notice on the MIS Secure Area, of ERCOT's intent to procure additional Ancillary Service Resources under Section 6.4.8.2, Supplemental Ancillary Service Market. ERCOT shall post the reliability reason for the increase in service requirements.

(5) ERCOT shall post engineering studies on the MIS Secure Area representing specific Ancillary Service requirement on an annual basis.

(6) The amount of Load Resources on high-set under-frequency relays providing RRS is limited to 50% of the total ERCOT RRS requirement. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation to be deployed.

(7) The amount of RRS that a QSE can self-arrange using a Load Resource excluding Controllable Load Resources is limited to the lower of:

(a) fifty percent (50%) of its RRS Obligation, or

(b) a reduced percentage of its RRS Obligation based on the limit established by ERCOT in paragraph (6) above.

(8) However, a QSE may bid more of the Load Resource above the percentage limit established by ERCOT for sale of RRS to other Market Participants. The total amount of Responsive Reserve Service using the Load Resource excluding Controllable Load Resources procured by ERCOT is also limited to the lesser of the 50% limit or the limit established by ERCOT in paragraph (6) above.

3.17 Ancillary Service Capacity Products

3.17.1 Regulation Service

(1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within three to five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled.

(2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within three to five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary

to maintain proper system frequency. A Generation Resource providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled.

3.17.2 Responsive Reserve Service

(1) Responsive Reserve Service (RRS) is a service used to restore or maintain the frequency of the ERCOT System:

(a) In response to, or to prevent, significant frequency deviations;

(b) As backup Regulation Service; and

(c) By providing energy during an EECP.

(2) RRS may be provided through one or more of the following means:

(a) By using frequency-dependent response from On-Line Resources as prescribed in the Operating Guides to help restore the frequency within the first few seconds of an event that causes a significant frequency deviation in the ERCOT System; and

(b) Either manually or by using a four-second signal to provide energy on deployment by ERCOT.

(3) Responsive Reserve Service may be used to provide energy during the implementation of an Emergency Electric Curtailment Plan (EECP). Under the EECP, RRS provides generation capacity, capacity from Controllable Load Resources or interruptible Load available for deployment on ten minutes' notice.

(4) Responsive Reserve Service (RRS) may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Load Resources controlled by high-set, under-frequency relays;

(c) Controllable Load Resources

(d) Load Resources capable of controllably reducing or increasing consumption under dispatch control (similar to AGC) and that immediately respond proportionally to frequency changes (similar to generator governor action);

(e) Hydro Responsive Reserves as defined in the Operating Guides; and

(f) DC Tie response that stops frequency decay as defined in the Operating Guides.

3.17.3 Non-Spinning Reserve Service

(1) Non-Spinning Reserve Service (Non-Spin) is provided by using:

(a) Generation Resources, whether On-Line or Off-Line, capable of:

(i) being synchronized and ramped to a specified output level within 30 minutes; and

(ii) running at a specified output level for at least one hour; or

(b) Load Resources capable of:

(i) being interrupted within 30 minutes; and

(ii) remaining interrupted for at least one hour.

(2) The Non-Spin may be deployed by ERCOT to increase available reserves in Real-Time Operations.

3.18 Resource Limits in Providing Ancillary Service

(1) The HSL must be greater than or equal to the LSL and the sum of the Resource-specific designation of capacity to provide Responsive Reserve, Reg-Up and Non-Spin;

(2) For Reg-Up, the amount of Reg-Up provided must be less than or equal to the HSL for Generation Resources and LPC for Load Resources minus the LSL for Generation Resources and MPC for Load Resources;

(3) For Reg-Down, the amount of Reg-Down provided must be less than or equal to the HSL for Generation Resources and LPC for Load Resources of the unit minus the LSL for Generation Resources and MPC for Load Resources; and

(4) For Non-Spin, the amount of Non-Spin provided must be less than or equal to the HSL for Generation Resources and LPC minus MPC for Load Resources; and

(5) For Responsive Reserve Service:

(a) The amount of RRS provided from a Generation Resource must be less than or equal to 20% of thermal unit HSL for an Ancillary Service Offer and must be less than or equal to 10 times the Emergency Ramp Rate;

(b) Hydro-powered Resources operating in the synchronous condenser fast-response mode may provide RRS up to the Resource's proved 20-second response (which may be 100% of the HSL);

(c) For any hydro-powered Resource with a five percent droop setting operating as a generator, the amount of RRS provided may never be more than 20% of the HSL; and

(d) The amount of RRS provided from a Load Resource must be less than or equal to the LPC minus the MPC.

3.19 Constraint Competitiveness Tests

(1) Unless the Board approves changes, the "Competitive Constraints" are the contingency/limiting Transmission Element pairs that represent the Commercially Significant Constraints (CSCs) and Closely Related Elements (CREs), as those terms were defined in the ERCOT Protocols, immediately prior to Texas Nodal Market Implementation Date. The ERCOT Board may approve changes to the Competitive Constraints from time to time, whether before the Texas Nodal Market Implementation Date or after. A contingency/limiting Transmission Element pair is designated a Competitive Constraint by TAC approval. Among other relevant factors, TAC shall consider the results of the Test Procedures 1 and 2, as described in Section 3.19.1, Annual Competitiveness Test in reaching its determination as to whether or not a Transmission Element pair should be considered as a Competitive Constraint. Any contingency/limiting Transmission Element pair not designated as a Competitive Constraint is deemed to be a non-competitive constraint.

(2) An appropriate subcommittee approved by TAC ("TAC Subcommittee") may develop an alternative list through the analysis described below for determining Competitive Constraints.

(3) The TAC Subcommittee shall perform the following analysis with the goal of developing an objective standard for determining Competitive Constraints:

(a) Contingency analysis – based on reasonable generation dispatch that would lead into a set of elements to be studied.

(b) Constraint Competitiveness Test (CCT) - using the parameters described in Section 3.19.1, Annual Competitiveness Test; Section 3.19.2, Monthly Competitiveness Test; and Section 3.19.3, Daily Competitiveness Test.

(c) Initial analysis of the CSCs and CREs and additional proposed contingency/limiting Transmission Element pairs for possible modifications or designation to their status as a Competitive Constraint must be completed prior to the Texas Nodal Market Implementation Date and subsequent analysis shall be on-going.

(d) At a minimum, the CCT should be performed at least once per month and the results compared to the existing TAC-approved Competitive Constraints list. Based on the comparison, the TAC Subcommittee may evaluate alternative methodologies or alternative Competitive Constraints and report the results of these evaluations to the TAC.

(4) The Independent Market Monitor (IMM) may suspend a Competitive Constraint from being designated as competitive for a specified period of time necessary to allow for analysis, but not to exceed 60 days. The IMM shall notify the market of the estimated time needed to conduct the analysis. The IMM shall notify the market of any suspended Competitive Constraint before suspension.

(5) TAC shall approve the Competitive Constraints one month prior to the annual CRR Auction. Prior to each monthly CRR Auction, TAC shall approve updates to the Competitive Constraints that are applicable for the following monthly auction. Any Competitive Constraint not determined to be competitive by TAC shall be deemed to be non-competitive.

(6) ERCOT shall post the Competitive Constraints to the MIS Secure Area at least five Business Days before any change takes effect. ERCOT shall post any Competitive Constraints that have been suspended and the duration of the suspension as soon as practicable to the MIS Secure Area.

3.19.1 Annual Competitiveness Test

(1) The procedures for an Annual Competitiveness Test for any constrained Transmission Element during a particular month are described in this Section. In these descriptions, "Available Capacity" for a Resource is defined as:

(a) The High Sustained Limit (HSL) of a Generation Resource, including a Switchable Generation Resource that is not on a Planned Outage for the month (except wind powered generation), or

(b) For wind generation, the expected on-peak wind generation output, or

(c) The full import capability of the DC Tie lines.

(2) **Test Procedure 1 –**Determine if there is sufficient competition to resolve the constraint on the import and export side by performing the following steps:

(a) Determine the effective capacity available to resolve the constraint on the import side, as follows:

(i) Determine shift factors of all Electrical Buses relative to the import terminal of the constraint as the reference Electrical Bus for the monthly peak case used to auction on-peak CRRs. The monthly peak case must include planned transmission and generation outages for the month. For voltage, stability, and thermal-limited constraints, as well as interfaces represented by thermal limits on monitored Transmission Elements, the "Base Shift Factors," which are the shift factors used from the monthly peak case with no other contingencies included, must be used. For contingency-limited constraints, the outage shift factors relative to the import terminal of the limiting Transmission Element must be used.

(ii) Determine the effective Load on the export side by multiplying all Load at Electrical Buses by the corresponding Electrical Bus shift factors identified in step (a)(i).

(iii) Determine the effective capacity needed to meet Load and to supply power over the constraint on the export side by:

(A) multiplying all Available Capacity at Electrical Buses by the corresponding shift factor from step (a)(i);

(B) stacking the effective capacity in decreasing shift factor order; and then

(C) selecting the sufficient effective capacity from the stack to meet the effective Load plus the flow limit on the constraint. These Resources shall not be considered in determining effective Available Capacity to resolve the constraint on the import side.

(iv) Determine the absolute value of shift factors of all Electrical Buses relative to the export terminal of the constraint as the reference Electrical Bus; and

(v) Determine the effective capacity to resolve the constraint on the import side taking the sum of the products determined by multiplying, for each Resource not excluded in step (a)(iii) and having shift factors greater than one-third of the highest Resource shift factor, (A) the Available Capacity for that Resource times (B) the shift factor of that Resource.

(b) Determine the effective capacity available to resolve the constraint on the export side, as follows:

(i) Determine the absolute value of shift factors of all Electrical Buses relative to the export terminal of the constraint as the reference Electrical Bus.

(ii) Determine the effective Load on the import side by multiplying all Load at Electrical Buses by the corresponding Electrical Bus shift factors from step (b)(i).

(iii) Determine the effective capacity needed to meet Load less imported power over the constraint on the import side by:

(A) multiplying all Available Capacity at Electrical Buses by the corresponding shift factor from step (b)(i);

(B) stacking the effective capacity in decreasing shift factor order; and then

(C) selecting the sufficient effective capacity from the stack to meet the effective Load minus the flow limit on the constraint. These Resources are not considered in determining effective capacity available to resolve the constraint on the export side.

(iv) Determine the shift factors of all Electrical Buses relative to the export terminal of the constraint as the reference Electrical Bus.

(v) Determine the effective capacity to resolve the constraint on the export side taking the sum of the products determined by multiplying, for each Resource not excluded in step (b)(iii) and having shift factors greater than one-third of the highest Resource shift factor, (A) the Available Capacity for that Resource times (B) the shift factor of that Resource.

(c) Determine the Element Competitive Index (ECI) on the import and export side of the constraint for the month, as follows:

(i) Determine the total Managed Capacity by each Entity and its Affiliates on the import and export side. Managed Capacity for an Entity is a Resource or portion of a Resource for which the Entity or its Affiliates has the decision-making authority over how the Resource or portion of the Resource is offered or scheduled (e.g., Output Schedules), either by virtue of ownership, agreement or otherwise. Each QSE shall submit annually a list of which Entity has that decision-making authority for each Resource or portion of a Resource the QSE represents. In addition, each QSE shall notify ERCOT of any known changes in that list no later than 1800 in the day prior to the date that the change takes effect. Each Resource Entity shall provide its QSE with the information necessary to comply with the foregoing requirements in a timely manner.

(ii) Determine the percentage of Managed Capacity by each Entity and its Affiliates on the import and export side.

(iii) The ECI on the import side is equal to the sum of the square of the percentages of Managed Capacity by each Entity and its Affiliates on the import side.

(iv) The ECI on the export side is equal to the sum of the square of the percentages of Managed Capacity by each Entity and its Affiliates on the export side.

(d) If the ECI is greater than 2,000 on the import side or the ECI is greater than 2,500 on the export side of the constraint for the month, then the constraint fails the competitive test for the month.

(3) **Test Procedure 2 –** Determining If There Is a Pivotal Player:

If the constraint satisfies the test for sufficient competition as described in Test Procedure 1, determine if there is a pivotal player in resolving the constraint in the manner described below: If the constraint cannot be resolved by eliminating all Available Capacity on the import side, except Nuclear capacity and Minimum-energy amounts of Coal and Lignite capacity as determined in Test Procedure 1 that is Managed Capacity by any one Entity and its Affiliates during peak Load conditions, then a pivotal player exists. A constraint satisfies this Test Procedure 2 if no Entity is a pivotal player.

3.19.2 Monthly Competitiveness Test

(1) Unless otherwise approved by TAC as a Competitive Constraint, the Monthly Competitiveness Test shall change the treatment of a Competitive Constraint to a non-competitive constraint for the particular month if the constraint meets the following conditions:

(a) The ECI is greater than 2,500 on the import side or the ECI is greater than 3,000 on the export side. The ECI is determined using the same procedure as the Annual Competitiveness Test but applied to the particular month only; or

(b) There is a pivotal player in resolving the constraint, which occurs when the constraint cannot be resolved by eliminating all Available Capacity on the import side, except Nuclear capacity and Minimum-energy amounts of Coal and Lignite that is Managed Capacity by any one Entity and its Affiliates during the peak case of the month.

(2) The ECI values established in the monthly test must be reviewed quarterly by the TAC Subcommittee for the proper value.

3.19.3 Daily Competitiveness Test

(1) Based on the set of the Competitive Constraints as determined in the Monthly Competitive Test, the Daily Competitiveness Test shall change the treatment of a Competitive Constraint to a non-competitive constraint for the particular day if the constraints meet the following conditions:

(a) The ECI is greater than 2,500 on the import side or the ECI is greater than 3,000 on the export side. The ECI is determined using the same procedure as the Annual Competitiveness Test but applied to the peak hour of the particular day; or

(b) There is a pivotal player in resolving the constraint, which occurs when the constraint cannot be resolved by eliminating all Available Capacity on the import side, except Nuclear capacity and Minimum-energy amounts of Coal and Lignite that is Managed Capacity by any one Entity and its Affiliates during the peak hour of the day.

(2) ERCOT shall post the Competitive Constraints to the MIS Secure Area by 0600 in the Day-Ahead.

(3) Available Capacity for the Daily Competitiveness Test is defined as the HSL of a Generation Resource, including a Switchable Generation Resource that is not the following: on Outage for the day (except wind powered generation), expected on-peak wind generation output, and full import capability of the DC Tie line.

(4) The ECI values established in the daily test must be reviewed quarterly for the proper value by the TAC Subcommittee.

ERCOT Nodal Protocols

Section 4: Day-Ahead Operations

Updated: August 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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4 DAY-AHEAD OPERATIONS

4.1 Introduction

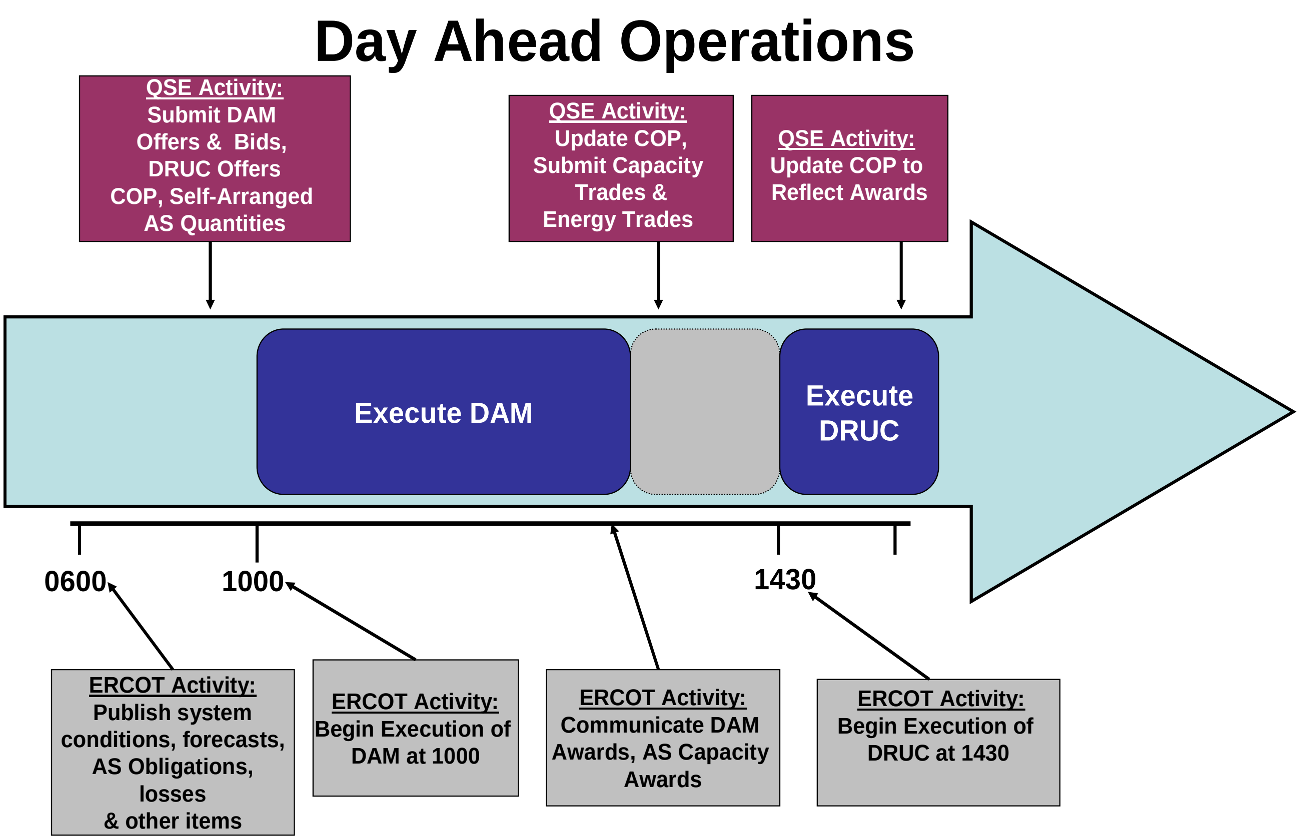
(1) The Day-Ahead Market (DAM) is a daily, co-optimized market in the Day-Ahead for Ancillary Service capacity, certain Congestion Revenue Rights, and forward financial energy transactions.

(2) Participation in the DAM is voluntary, except for Reliability Must Run (RMR) Units, the participation of which is governed by their respective RMR Agreements and Section 4.4.8, RMR Offers.

(3) DAM energy settlements use DAM Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a one-hour Settlement Interval using the LMPs from DAM. In contrast, the Real-Time energy settlements use Real-Time Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a 15-minute Settlement Interval.

4.1.1 Day-Ahead Timeline Summary

The figure below shows the major activities that occur in the Day-Ahead:



4.1.2 Day-Ahead Process and Timing Deviations

(1) ERCOT may temporarily deviate from the timing of its obligations in this Section but only to the extent necessary to ensure the secure operation of the ERCOT System. In that event, ERCOT shall immediately issue an Alert and notify all QSEs of the following:

(a) Details of the affected timing and procedures;

(b) Details of any interim requirements;

(c) An estimate of the period for which the interim requirements apply; and

(d) Reasons for the temporary variation.

(2) If, despite the varying timing or omitting any procedure, ERCOT is unable to execute the Day-Ahead process, ERCOT may abort all or part of the Day-Ahead process and require all schedules and trades to be submitted in the Adjustment Period. In that event, ERCOT shall declare an Emergency Condition and notify all QSEs of the following:

(a) Details of the affected timing and procedures;

(b) Details of any interim requirements;

(c) An estimate of the period for which the interim requirements apply; and

(d) Reasons for the temporary variation.

(3) If, despite varying timing or omitting steps, ERCOT is unable to operate the Adjustment Period process, then ERCOT may abort the Adjustment Period process and operate under its Operating Period procedures.

4.2 ERCOT Activities in the Day-Ahead

4.2.1 Ancillary Service Plan and Ancillary Service Obligation

4.2.1.1 Ancillary Service Plan

(1) ERCOT shall analyze the expected Load conditions for the Operating Day and develop an Ancillary Service Plan that identifies the Ancillary Service MW necessary for each hour of the Operating Day. The MW of each Ancillary Service required may vary from hour to hour depending on ERCOT System conditions. ERCOT must post the Ancillary Service Plan to the MIS Public Area by 0600 of the Day-Ahead.

(2) If ERCOT determines that an Emergency Condition may exist that would adversely affect ERCOT System reliability, it may change the percentage of Load Resources that are allowed to provide Responsive Reserve Service (RRS) from

the monthly amounts determined previously, as described in Section 3.16, Standards for Determining Ancillary Service Quantities, and must post any change in the percentage to the MIS Public Area by 0600 of the Day-Ahead.

(3) ERCOT shall determine the total required amount of each Ancillary Service under Section 3.16, or use its operational judgment and experience to change the daily quantity of each required Ancillary Service.

(4) ERCOT shall include in the Ancillary Service Plan enough capacity to automatically control frequency with the intent to meet NERC standards.

(5) ERCOT shall notify the QSE representing an RMR Unit for any unit that is being committed in the DAM or the DRUC at the same time that the DAM and DRUC participants are notified of the results of that respective process.

(6) Once specified by ERCOT for an hour and published on the MIS Public Area, Ancillary Service quantity requirements for an Operating Day may not be decreased.

4.2.1.2 Ancillary Service Obligation Assignment and Notice

(1) ERCOT shall assign part of the Ancillary Service Plan quantity, by service, by hour, to each LSE based on Load Ratio Share and shall then aggregate those quantities, by service, by hour to the QSE level. The resulting Ancillary Service quantity for each QSE, by service, by hour, is called its Ancillary Service Obligation. ERCOT shall base the LSE Ancillary Service allocation on the hourly Load Ratio Share from the real time market data used for Initial Settlement for the same hour and day of the week, for the most recent day for which Initial Settlement Statements are available, multiplied by the quantity of that service required in the Day-Ahead Ancillary Service Plan. The Ancillary Service Obligation defined shall be adjusted based on the most current real time settlement and resettlement data for the Operating Day for which the Ancillary Service was procured.

(2) By 0600 of the Day-Ahead, ERCOT shall notify each QSE of its Ancillary Service Obligation for each service and for each hour of the Operating Day.

(3) By 0600 of the Day-Ahead, ERCOT shall post on the MIS Certified Area each QSE's Load Ratio Share used for the Ancillary Service Obligation calculation.

4.2.2 Wind-Powered Generation Resource Production Potential

(1) ERCOT shall produce and update hourly a Short-Term Wind Power Forecast (STWPF) that provides a rolling 48-hour hourly forecast of wind production potential for each Wind-Powered Generation Resource (WGR). ERCOT shall produce and update an hourly Total ERCOT Wind Power Forecast (TEWPF) providing a probability distribution of the hourly production potential from all wind-power in ERCOT for each of the next 48 hours. Each Generation Entity

that owns a WGR shall install and telemeter to ERCOT the site-specific meteorological information that ERCOT determines is necessary to produce the STWPF and TEWPF forecasts. ERCOT shall establish procedures specifying the accuracy requirements of WGR meteorological information telemetry.

(2) The WGR Production Potential (WGRPP) is an hourly 80% probability of exceedance forecast of energy production for each WGR. ERCOT shall use the probabilistic TEWPF and select the forecast that the actual total ERCOT WGR production is expected to exceed 80% of the time (80% probability of exceedance forecast). To produce the WGRPP ERCOT will allocate the TEWPF 80% probability of exceedance forecast to each WGR such that the sum of the individual WGRPP forecasts equal the TEWPF forecast. The updated WGRPP forecasts for each hour for each WGR are to be used as input into each RUC process as per Section 5, Transmission Security Analysis and Reliability Unit Commitment.

(3) ERCOT shall produce the WGRPP forecasts using the information provided by WGR owners including WGR availability, meteorological information, and SCADA.

(4) Each hour, ERCOT shall provide, through the Messaging System, the WGRPP forecasts for each WGR to the QSE that represents that WGR and shall post each WGRPP forecast on the MIS Certified Area.

(5) Each hour, ERCOT shall post the TEWPF 80% probability of exceedance forecast on the MIS Secure Area. ERCOT shall retain the TEWPF for each hour.

(6) ERCOT shall post to the Market Information System, on a regional basis a rolling 48 hour actual wind power production and the forecasted amounts from the STWPF and the TEWPF.

4.2.3 Posting Forecasted ERCOT System Conditions

No later than 0600 in the Day-Ahead, ERCOT shall post on the MIS Secure Area, and make available for download, the following information for the Operating Day:

(a) The Network Operations Model topology that includes known transmission line and other Transmission Facilities Outages in the Common Information Model format for the minimum Load hour and the peak Load hour;

(b) Weather assumptions used by ERCOT to forecast ERCOT System conditions and used in the Dynamic Rating Processor;

(c) Any weather-related changes to the transmission contingency list;

(d) ERCOT System, Weather Zone, and Load Zone Load forecasts for the next seven days, by hour, and a message on update indicating any changes to the forecasts by means of the Messaging System;

(e) Load forecast distribution factors from which Market Participants can calculate Load at the Electrical Bus level by hour for the next seven days;

(f) Load Profiles for non-IDR metered Customers;

(g) Distribution Loss Factors and forecasted ERCOT-wide Transmission Loss Factors, as described in Section 13.3, Distribution Losses and in Section 13.2, Transmission Losses, for each Settlement Interval of the Operating Day;

(h) A current list of all Settlement Points that may be used for market processes and transactions;

(i) A mapping of Settlement Points to Electrical Buses in the Network Operations Model; and

(j) A list of transmission constraints that have a high probability of binding in the Security-Constrained Economic Dispatch (SCED) or DAM.

4.2.4 ERCOT Notice of Validation Rules for the Day-Ahead

ERCOT shall provide each QSE with the information necessary to pre-validate its data for DAM, including publishing validation rules for offers, bids and trades and posting any software documentation and code that is not Protected Information to the MIS Secure Area within five Business Days after ERCOT receives it.

4.3 QSE Activities and Responsibilities in the Day-Ahead

(1) During the Day-Ahead, a QSE:

(a) Must submit its COP and update its COP as required in Section 3.9, Current Operating Plan (COP);

(b) May submit Three-Part Supply Offers, DAM Energy-Only Offers, DAM Energy Bids, Energy Trades, Self-Schedules, Capacity Trades, DC Tie Schedules, Ancillary Service Offers, Ancillary Service Trades, Self-Arranged Ancillary Service Quantities, PTP Obligation Bids, and CRR Offers as specified in this Section; and

(2) By 0600 in the Day-Ahead, each QSE representing RMR Units, or Black Start Resources shall submit information to ERCOT indicating availability of RMR Units, and Black Start Resources for the Operating Day, and any other information that ERCOT may need to evaluate use of the units as set forth in the applicable Agreements and this Section.

4.4 Inputs into DAM and Other Trades

4.4.1 Capacity Trades

(1) A Capacity Trade is the information for a QSE-to-QSE transaction that transfers financial responsibility for capacity between a buyer and a seller.

(2) A Capacity Trade for hours in the Operating Day that is reported to ERCOT before 1430 in the Day-Ahead creates:

(i) A capacity supply in the DRUC process for the buyer; and

(ii) A capacity obligation in the DRUC process for the seller.

(3) A Capacity Trade submitted at or after 1430 in the Day-Ahead for the Operating Day creates a capacity supply or obligation in any HRUC processes executed after the Capacity Trade is reported to ERCOT. Capacity Trades submitted after the DRUC snapshot are considered in the Adjustment Period snapshot.

(4) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Capacity Trades that are invalid Capacity Trades. The QSE may correct and resubmit any invalid Capacity Trade within the appropriate market timeline.

4.4.1.1 Capacity Trade Criteria

(1) A Capacity Trade must be submitted by a QSE and must include the following:

(a) The buying QSE;

(b) The selling QSE;

(c) The quantity in MW; and

(d) The first hour and last hour of the trade.

(2) A Capacity Trade must be confirmed by both the buyer and seller to be considered valid.

4.4.1.2 Capacity Trade Validation

(1) A validated Capacity Trade is a Capacity Trade that ERCOT has determined meets the criteria listed in Section 4.4.1.1, Capacity Trade Criteria. Only one confirmed Capacity Trade is allowed for the same buying and selling QSEs for each hour.

(2) When a Capacity Trade is reported to ERCOT, ERCOT shall notify both the buying and selling QSEs by using the Messaging System, if available, and on the MIS Certified Area.

(3) ERCOT shall continuously validate Capacity Trades and continuously display on the MIS Certified Area information that allows any QSE named in a Capacity Trade to view confirmed and unconfirmed Capacity Trades.

(4) The QSE that first reports the Capacity Trade to ERCOT is deemed to have confirmed the Capacity Trade unless it subsequently affirmatively rejects it. The QSE that first reports a Capacity Trade may reject, edit, or delete a Trade that its counterpart has not confirmed. The counterpart is deemed to have confirmed the Capacity Trade when it submits to ERCOT an identical Capacity Trade. After both the buyer and seller have confirmed a Capacity Trade, either party may reject it at any time, but the rejection is effective only for any ERCOT settlement process for which the deadline for reporting Capacity Trades has not yet passed.

4.4.2 Energy Trades

(1) An Energy Trade is the information for a QSE-to-QSE transaction that transfers financial responsibility for energy at a Settlement Point between a buyer and a seller.

(2) An Energy Trade for hours in the Operating Day that is reported to ERCOT before 1430 in the Day-Ahead creates a capacity supply or obligation in the DRUC process. Energy Trades submitted after 1430 in the Day-Ahead for the Operating Day create a capacity supply or obligation in any HRUC processes executed after the Energy Trade is reported to ERCOT. Energy Trades submitted after the DRUC snapshot are considered in the Adjustment Period.

(3) An Energy Trade may be submitted for any Settlement Interval within an Operating Day before 1430 of the following day.

(4) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Energy Trades that are invalid Energy Trades. The QSE may correct and resubmit any invalid Energy Trade within the appropriate market timeline.

4.4.2.1 Energy Trade Criteria

(1) Each Energy Trade must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The selling QSE;

(c) The quantity of MW for each 15-minute Settlement Interval of the trade;

(d) The first and last 15-minute Settlement Intervals of the trade; and

(e) The Settlement Point of the trade.

(2) An Energy Trade must be confirmed by both the buyer and seller to be considered valid.

4.4.2.2 Energy Trade Validation

(1) A validated Energy Trade is an Energy Trade that ERCOT has determined meets the criteria listed in Section 4.4.2.1, Energy Trade Criteria. Only one confirmed Energy Trade is allowed for the same buying and selling QSEs at the same Settlement Point for each 15-minute Settlement Interval.

(2) When an Energy Trade is reported to ERCOT, ERCOT shall notify both the buying and selling QSEs by using the Messaging System if available and the MIS Certified Area.

(3) ERCOT shall continuously validate Energy Trades and continuously display on the MIS Certified Area information that allows any QSE named in an Energy Trade to view confirmed and unconfirmed Energy Trades.

(4) The QSE that first reports the Energy Trade to ERCOT is considered to have confirmed the Energy Trade unless it subsequently affirmatively rejects it. The QSE that first reports an Energy Trade may reject, edit, or delete an Energy Trade that its counterpart has not confirmed. The counterpart is deemed to have confirmed the Energy Trade when it submits an identical Energy Trade. After both the buyer and seller have confirmed an Energy Trade, either party may reject it at any time, but the rejection is effective only for any ERCOT process for which the deadline for reporting Energy Trades has not yet passed.

4.4.3 Self-Schedules

(1) A Self-Schedule is the information that a QSE submits for Real-Time Settlement that specifies the amount of the QSE's energy supply at a specified source Settlement Point to be used to meet the QSE's energy obligation at a specified sink Settlement Point .

(2) A Self-Schedule may be submitted for any Settlement Interval before the end of the Adjustment Period for that Settlement Interval.

(3) As soon as practicable, ERCOT shall notify the QSE through the Messaging System of any of its Self-Schedules that are invalid Self-Schedules. The QSE may correct and resubmit any invalid Self-Schedule within the appropriate market timeline.

4.4.3.1 Self-Schedule Criteria

(1) Each Self-Schedule must be reported by a QSE and must include the following information:

(a) The name of the QSE;

(b) The quantity of MW for each 15-minute Settlement Interval of the schedule;

(c) The first and last 15-minute Settlement Intervals of the schedule; and

(d) The source Settlement Point of the schedule;

(e) The sink Settlement Point of the schedule.

4.4.3.2 Self-Schedule Validation

(1) A validated Self-Schedule is a Self-Schedule that ERCOT has determined meets the criteria listed in Section 4.4.3.1, Self-Schedule Criteria.

(2) ERCOT shall continuously validate Self-Schedules and continuously display on the MIS Secure Area information that allows the QSE named in a Self-Schedule to view validated Self-Schedules.

4.4.4 DC Tie Schedules

(1) A DC Tie Schedule is the information for a physical transaction between a buyer and a seller, one of which is in ERCOT and the other of which is in a Non-ERCOT Control Area, for energy at a Settlement Point that is a DC Tie. A DC Tie Schedule must be implemented under these Protocols, any applicable NERC scheduling protocols, any applicable NERC operating policies, and any applicable operating agreements between ERCOT and Mexico. A DC Tie Schedule must be transaction-specific, i.e., one schedule per transaction per DC Tie, rather than aggregate (net) schedules per DC Tie.

(2) Each QSE shall follow all NERC policies for tagging of Control Area interchange transactions. Only transactions across ERCOT interconnections to SPP, WSCC, Mexico, or other areas must be tagged by the QSE as prescribed in the NERC tagging guidelines.

(3) A DC Tie Schedule for hours in the Operating Day that is reported to ERCOT before 1430 in the Day-Ahead creates a capacity supply or for the equivalent Resource or an obligation for the equivalent load of the DC Tie in the DRUC process. DC Tie Schedules submitted after 1430 in the Day-Ahead for the Operating Day create a capacity supply or obligation in any applicable HRUC processes executed after the DC Tie Schedule is reported to ERCOT. DC Tie Schedules submitted after the RUC snapshot are considered in the Adjustment Period snapshot in accordance with the market timeline.

(4) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its DC Tie Schedules that are invalid DC Tie Schedules. The QSE may correct and resubmit any invalid DC Tie Schedules within the appropriate market timeline.

(5) A QSE that is an importer into ERCOT through a DC Tie in a Settlement Interval under a DC Tie Schedule must be treated as a Resource at that DC Tie Settlement Point for that Settlement Interval.

(6) A QSE that is an exporter from ERCOT through a DC Tie in a Settlement Interval under a DC Tie Schedule must be treated as a Load at the DC Tie Settlement Point for that Settlement Interval and is responsible for allocated Transmission Losses, UFE System Administration Fee, and any other applicable ERCOT fees. This applies to all exports across the DC Ties except those that qualify for the Oklaunion Exemption.

(7) ERCOT shall confirm each valid DC Tie Schedule with the applicable interconnected non-ERCOT Control Area and shall coordinate the approval process for the NERC tags for the ERCOT Control Area.

(8) Using the DC Tie Schedule information submitted by QSEs, ERCOT shall update and maintain a Current Operating Plan for each DC Tie for which the aggregated DC Tie Schedules for that tie show a net export out of ERCOT for the applicable interval. When the net energy schedule for a DC Tie indicates an export, ERCOT shall treat the DC Tie as an Off-Line Resource and set the HSL and LSL for that DC Tie Resource to zero. ERCOT shall monitor the associated Resource Status telemetry during the Operating Period. When the net energy schedule for a DC Tie shows a net import, the Resource HSL, HASL and LSL must be set appropriately, considering the resulting net import and any Ancillary Service Schedules for the DC Tie Resource.

(9) A QSE submitting a DC Tie Schedule shall:

(a) Secure and maintain a NERC tag service to submit NERC tags and monitor NERC tag status according to NERC requirements;

(b) Submit NERC tags for all proposed transactions; and

(c) Implement backup procedures in case of NERC tag service failure.

4.4.4.1 DC Tie Schedule Criteria

(1) Each DC Tie Schedule must be submitted by a QSE and must include the following information:

(a) The QSE or non-ERCOT Control Area buying the energy;

(b) The QSE or non-ERCOT Control Area selling the energy;

(c) For each DC Tie Schedule, the DC Tie Settlement Point;

(d) The quantity in MW for each 15-minute Settlement Interval of the schedule;

(e) The first and last 15-minute Settlement Intervals of the schedule; and

(f) The NERC tag information, which must conform to the standards set forth in NERC Policy 3 and associated appendixes.

(2) A DC Tie Schedule must be intended to match what the submitting QSE reasonably expects the DC Tie Schedule to be in Real-Time.

(3) A DC Tie Schedule must be confirmed by the non-ERCOT Control Area to be considered valid.

4.4.4.2 DC Tie Schedule Validation

(1) A validated DC Tie Schedule is a DC Tie Schedule that ERCOT has determined:

(a) Meets the criteria listed in Section 4.4.4.1, DC Tie Schedule Criteria;

(b) Is matched—in quantity, time period, DC Tie Settlement Point, and other NERC tag information—by a schedule submitted by a non-ERCOT Control Area; and

(c) For the NERC tag:

(i) All Control Areas and transmission service providers with approval rights approve the NERC tag (active approval); or

(ii) No Entity with approval rights over the NERC tag has denied it, and the approval time window has ended (passive approval).

(2) Any changes in the interconnected non-ERCOT Control Area schedules due to a de-rating of the DC Tie or other change within the NERC or Mexico's scheduling protocols must be communicated to ERCOT by the DC Tie Operator or designated reliability authority for the interconnected non-ERCOT Control Area. For any interconnected non-ERCOT Control Area schedules revised during the Operating Period, the DC Tie Operator shall communicate to ERCOT the integrated schedule for the Settlement Intervals. If the DC Tie Schedule flows as planned, then ERCOT shall use schedules as the deemed meter readings for Real-Time settlement. If the interconnected non-ERCOT Control Area schedule changes during the Operating Period, then ERCOT shall use the changed interconnected non-ERCOT Control Area schedule as the deemed meter reading for Real-Time settlement.

4.4.4.3 Oklaunion Exemption

(1) The export schedules from the Public Service Company of Oklahoma, the Oklahoma Municipal Power Authority, and the AEP Texas North Company for their share of the Oklaunion Resource over the North DC Tie are not treated as Load connected at transmission voltage, are not subject to any of the fees described in Section 4.4.4, DC Tie Schedules, and are limited to the actual net

output of the Oklaunion Resource (“Oklaunion Exemption”). ERCOT shall record DC Tie Schedules that qualify for the Oklaunion Exemption to support the billing of applicable TSP tariffs.

(2) A QSE requesting the Oklaunion Exemption shall:

(a) Apply to ERCOT for the exemption;

(b) Set up a separate QSE (or sub-QSE) solely to schedule DC Tie exports under the exemption; and

(c) Secure the Resources for a DC Tie Schedule by a DC Tie Schedule from each QSE representing part or all the Oklaunion Resource.

(3) ERCOT shall verify for each Settlement Interval that the sum of the “exempted” exports under the Oklaunion Exemption is not more than the total output from the Oklaunion Resource.

4.4.5 CRR Offers

(1) A CRR Offer is the information for an offer by a CRR Account Holder to sell CRRs that it owns in the DAM.

(2) All CRRs held by CRR Account Holders are settled based on applicable DAM settlement prices, except for PTP Options and PTP Options with Refund that have been declared by a NOIE before DAM execution to be settled in Real-Time and are still held by that NOIE in Real-Time.

(3) PTP Options and PTP Options with Refund that are declared by NOIEs for Real-Time settlement may specify an offer price (Minimum Reservation Price) in the DAM. If no Minimum Reservation Price is specified, ERCOT shall assign a default value of $2,000 per MW per hour, as an offer in the DAM. If such an offer clears in the DAM, it is settled as part of the DAM and is not carried to Real-Time.

4.4.5.1 CRR Offer Criteria

(1) A CRR Offer must include the following:

(a) The name of the CRR Account Holder that owns the CRRs being offered;

(b) The unique identifier for each CRR being offered, which includes the single type of CRR being offered;

(c) The source Settlement Point and the sink Settlement Point for the CRR or block of CRRs being offered;

(d) The first hour and the last hour for which the CRR or block of CRRs is being offered;

(e) The quantity of CRRs in MW for which the Minimum Reservation Price is effective;

(f) A dollars per MW per hour for the Minimum Reservation Price; and

(g) For PTP Options that a NOIE has designated for Real-Time settlement, the NOIE peak Load forecast for the Operating Day.

(2) The CRR Account Holder for whom the CRR Offer is being submitted must be shown as the owner in the ERCOT CRR registration system of the CRRs being offered.

(3) If the CRR Offer is for more than one CRR (which is 1 MW for one hour), the CRR Offer must have the following characteristics:

(a) All CRRs must be of the same type;

(b) All CRRs must have the same source and sink Settlement Points, and

(c) A block CRR Offer must have the same number of CRRs offered in each hour; and

(d) A block CRR Offer must have contiguous hours for the CRRs offered.

(4) For each NOIE that designated PTP Options or PTP Options with Refund for Real-Time settlement, the designation of such CRRs to be settled in Real-Time may not exceed 110% of that NOIE's peak Load forecast.

4.4.5.2 CRR Offer Validation

(1) A validated CRR Offer is a CRR Offer that ERCOT has determined meets the criteria listed in Section 4.4.5.1, CRR Offer Criteria.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any QSE submitting a CRR Offer to view its valid CRR Offers.

(3) As soon as practicable, ERCOT shall notify each CRR Account Holder through the Messaging System of any of its CRR Offers that are invalid. The CRR Account Holder may correct and resubmit any invalid CRR Offer within the appropriate market timeline.

4.4.6 PTP Obligation Bids

(1) A PTP Obligation Bid is a bid that specifies the source and sink, a range of hours, and a maximum price that the bidder is willing to pay ("Not-to-Exceed Price").

(2) PTP Obligations that are bought in the DAM must be settled based on the applicable Real-Time Settlement Point Prices.

4.4.6.1 PTP Obligation Bid Criteria

(1) A PTP Obligation Bid must be submitted by a QSE and must include the following:

(a) The name of the QSE submitting the PTP Obligation Bid;

(b) The source Settlement Point and the sink Settlement Point for the PTP Obligation or block of PTP Obligations being bid;

(c) The first hour and the last hour for which the PTP Obligation or block of PTP Obligations is being bid;

(d) The quantity of PTP Obligations in MW for which the Not-to-Exceed Price is effective; and

(e) A dollars per MW per hour for the Not-to-Exceed Price.

(2) If the PTP Obligation Bid is for more than one PTP Obligation (which is 1 MW for one hour), the block bid must:

(a) Include the same number of PTP Obligations in each hour of the block;

(b) Be for PTP Obligations that have the same source and sink Settlement Points; and

(c) Be for contiguous hours.

4.4.6.2 PTP Obligation Bid Validation

(1) A validated PTP Obligation Bid is a bid that ERCOT has determined meets the criteria listed in Section 4.4.6.1, PTP Obligation Bid Criteria.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any QSE submitting a PTP Obligation Bid to view its valid PTP Obligation Bid.

(3) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its PTP Obligation Bids that are invalid. The QSE may correct and resubmit any invalid PTP Obligation Bid within the appropriate market timeline.

4.4.7 Ancillary Service Supplied and Traded

4.4.7.1 Self-Arranged Ancillary Service Quantities

(1) A QSE may self-arrange all or a portion thereof, but not to exceed, the Ancillary Service Obligation allocated to it by ERCOT. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation.

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, needs to be obtained through the DAM.

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities unless ERCOT opens a Supplemental Ancillary Service Market.

(4) Before 1430 in the Day-Ahead, all Self-Arranged Ancillary Service Quantities must be represented by physical capacity, either by Generation Resources or Load Resources, or backed by Ancillary Service Trades.

(5) When a QSE chooses to self-arrange all or a portion of its Ancillary Service Obligations, it commits to the following conditions:

(a) The QSE may self-arrange Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), Responsive Reserve Service (RRS), and Non-Spin;

(b) The QSE may provide all or part of its Self-Arranged Ancillary Service Quantity from one or more Resources it represents;

(c) The QSE may provide all or a part of its Self-Arranged Ancillary Service Quantity through an Ancillary Service Trade;

(d) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a Supplemental Ancillary Service Market notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than the additional Ancillary Service amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT; and

(e) If a QSE does not self-arrange all of its Ancillary Service Obligation, ERCOT shall procure the remaining amount of the Ancillary Service Obligation for the QSE.

4.4.7.2 Ancillary Service Offers

(1) By 1000 in the Day-Ahead, a QSE may submit Generation Resource-specific Ancillary Service Offers to ERCOT for the DAM and may offer the same Generation Resource capacity for any or all of the Ancillary Service products simultaneously with any Energy Offer Curves from that Generation Resource in the DAM. A QSE may also submit Ancillary Service Offers in a Supplemental Ancillary Service Market (SASM). Offers of more than one Ancillary Service product from one Generation Resource may be inclusive or exclusive of each other and of any Energy Offer Curves, as specified according to a procedure developed by ERCOT.

(2) By 1000 in the Day-Ahead, a QSE may submit Load Resource-specific Ancillary Service Offers for Regulation Service, Non-Spinning Reserve Service and Responsive Reserve Service to ERCOT and may offer the same Load Resource capacity for any or all of those Ancillary Service products simultaneously. Offers of more than one Ancillary Service product from one Load Resource may be inclusive or exclusive of each other, as specified according to a procedure developed by ERCOT.

(3) Ancillary Service Offers remain active for the offered period until either:

(a) Selected by ERCOT;

(b) Automatically inactivated by the software at the offer expiration time specified by the QSE when the offer is submitted; or

(c) Withdrawn by the QSE, but a withdrawal is not effective if the deadline for submitting offers has already passed.

(4) A Load Resource that is not a Controllable Load Resource may specify whether its Ancillary Service Offer for Responsive Reserve Service may only be procured by ERCOT as a block.

4.4.7.2.1 Ancillary Service Offer Criteria

(1) Each Ancillary Service Offer must be submitted by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) The quantity in MW and Ancillary Service type from that Resource for this specific offer and the specific quantity in MW and Ancillary Service type of any other Ancillary Service offered from this same capacity;

(d) An Ancillary Service Offer linked to a Three-Part Supply Offer from a Resource designated to be Off-Line for the offer period in its COP may only be struck if the Three-Part Supply Offer is struck. The total capacity struck must be within limits as defined in item (4)(c)(iii) of Section 4.5.1, DAM Clearing Process.

(e) An Ancillary Service Offer linked to other Ancillary Service offers or an Energy Offer Curve from a Resource designated to be On-Line for the offer period in its COP may only be struck if the total capacity struck is within limits as defined in item (4)(c)(iii) of Section 4.5.1.

(f) The first and last hour of the offer;

(g) A fixed quantity block, or variable quantity block indicator for the offer;

(i) If a fixed quantity block, not to exceed 150 MW, which may only be offered by a Load Resource, the single price (in $/MW) and single quantity (in MW) for all hours offered in that block;

(ii) If a variable quantity block, which may be offered by a Generation Resource or a Load Resource, the single price (in $/MW) and single "up to" quantity (in MW) contingent on the purchase of all hours offered in that block; and

(h) The expiration time and date of the offer.

(2) A valid Ancillary Service Offer in the DAM must be received before 1000 for the effective DAM. A valid Ancillary Service Offer in a SASM must be received before the applicable deadline for that SASM.

(3) No Ancillary Service Offer price may exceed the System-Wide Offer Cap (in $/MW).

(4) The minimum amount per Resource for each Ancillary Service product that may be offered is one MW.

(5) A Resource may offer more than one Ancillary Service.

(6) A Load Resource that is qualified to perform as a Controllable Load Resource may not offer to provide Ancillary Services as a Controllable Load Resource and a Load Resource controlled by high-set under-frequency relay simultaneously behind a common breaker.

4.4.7.2.2 Ancillary Service Offer Validation

(1) A valid Ancillary Service Offer is one that ERCOT has determined meets the criteria listed in Section 4.4.7.2.1, Ancillary Service Offer Criteria.

(2) ERCOT shall continuously validate Ancillary Service Offers and continuously display on the MIS Certified Area information that allows any QSE named in an Ancillary Service Offer to view its confirmed Ancillary Service Offers.

(3) ERCOT shall notify the QSE submitting an Ancillary Service Offer if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the offer within the appropriate market timeline.

4.4.7.3 Ancillary Service Trades

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

(3) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Ancillary Service Trades that are invalid Ancillary Service Trades. The QSE may correct and resubmit any invalid Ancillary Service Trade, but the reporting time of the trade is determined by when the validated Ancillary Service Trade was submitted and not when the original invalid Ancillary Service Trade was submitted.

4.4.7.3.1 Ancillary Service Trade Criteria

(1) Each Ancillary Service Trade must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The selling QSE;

(c) The type of Ancillary Service;

(d) The quantity in MW; and

(e) The first and last hours of the trade.

(2) An Ancillary Service Trade must be confirmed by both the buyer and seller to be considered valid and to be used in an ERCOT process.

4.4.7.3.2 Ancillary Service Trade Validation

(1) A valid Ancillary Service Trade is an Ancillary Service Trade that ERCOT has determined meets the criteria listed in Section 4.4.7.3.1, Ancillary Service Trade Criteria. Only one confirmed Ancillary Service Trade is allowed for the same buying and selling QSEs for each type of Ancillary Service for each hour.

(2) When an Ancillary Service Trade is reported to ERCOT, ERCOT shall notify both the buying and selling QSEs by using the Messaging System if available and the MIS Certified Area.

(3) ERCOT shall continuously validate Ancillary Service Trades and continuously display on the MIS Certified Area information that allows any QSE named in an Ancillary Service Trade to view its confirmed and unconfirmed Ancillary Service Trades.

(4) The QSE that first reports the Ancillary Service Trade to ERCOT is deemed to have confirmed the Ancillary Service Trade unless it subsequently affirmatively rejects it. The QSE that first reports an Ancillary Service Trade may reject, edit, or delete an Ancillary Service Trade that its counterpart has not confirmed. The counterpart is deemed to have confirmed the Ancillary Service Trade when it submits an identical Ancillary Service Trade. After both the buyer and seller have confirmed an Ancillary Service Trade, either party may reject it at any time, but the rejection is effective only for any ERCOT process for which the deadline for reporting Ancillary Service Trades has not yet passed.

4.4.7.4 Ancillary Service Supply Responsibility

(1) A QSE's Ancillary Service Supply Responsibility is the net amount of Ancillary Service capacity that the QSE is obligated to deliver to ERCOT, by hour and service type, from Resources represented by the QSE. The Ancillary Service Supply Responsibility is the difference in MW, by hour and service type, between the amounts specified in (a) and (b) defined as follows:

(a) The sum of:

(i) the QSE's Self-Arranged Ancillary Service Quantity;

(ii) the total (in MW) of Ancillary Service Trades for which the QSE is the seller; plus

(iii) Awards to the QSE of Ancillary Service Offers in the DAM; and

(b) The total Ancillary Service Trades for which the QSE is the buyer.

(2) A QSE may only use a Resource to provide its Ancillary Service during non-RUC-Committed Intervals.

(3) By 1430 in the Day-Ahead, the QSE must notify ERCOT, in the QSE's COP, which Resources represented by the QSE will provide the Ancillary Service capacity necessary to meet the QSE's Ancillary Service Supply Responsibility, specified by Resource, hour, and service type. The DAM Ancillary Service awards are Resource-specific; the QSE must include those DAM awards in its COP, and the QSE may not change that Resource-specific DAM award information until after 1600 under the conditions set out in Section 3.9, Current Operating Plan (COP).

(4) Section 6.4.8.1.3, Replacement of Ancillary Service Due to Failure to Provide, specifies what happens if the QSE fails on its Ancillary Service Supply Responsibility.

4.4.8 RMR Offers

ERCOT shall decide, in its sole discretion, when to make an RMR Unit available for commitment in DRUC, HRUC, or DAM, considering relevant factors such as whether it is likely to be needed in Real-Time for reliability reasons, whether SCED will solve operating constraints, contractual constraints on the Resource, and any other adverse effects on the RMR Unit that may occur as the result of the dispatch of the RMR Resource.

(a) By 1000 in the Day-Ahead, ERCOT shall submit, in ERCOT's sole discretion, Three-Part Supply Offers based on RMR Agreement rates and any other relevant information as provided under contract on behalf of RMR Units for any RMR Units to be considered, in the DAM, DRUC, or HRUC.

(b) ERCOT may submit Energy Offer Curves based on RMR Agreement rates and any other relevant information as provided under contract on behalf of RMR Units committed in the DAM, DRUC, or HRUC.

4.4.9 Energy Offers and Bids

4.4.9.1 Three-Part Supply Offers

(1) A Three-Part Supply Offer consists of a Startup Offer, a Minimum-Energy Offer, and an Energy Offer Curve. ERCOT must validate each Startup Offer, Minimum-Energy Offer, and Energy Offer Curve before it can be used in any ERCOT process.

(2) The DAM uses all three parts of the Three-Part Supply Offer and also uses Energy Offer Curves submitted without a Startup Offer and without a Minimum-Energy Offer. The RUC only uses the Startup Offer and the Minimum-Energy Offer components for determining RUC commitments, but the Energy Offer Curve may be used in settlement to claw back some or all of a RUC-committed Resource's energy payments. The Energy Offer Curve may also be used by SCED in Real-Time Operations.

(3) A QSE may submit an Energy Offer Curve without also submitting a Startup Offer and a Minimum-Energy Offer for the DAM and during the Adjustment Period, but only Three-Part Supply Offers are used in the RUC process. A QSE that submits an Energy Offer Curve without also submitting a Startup Offer and a Minimum-Energy Offer is considered not to be offering the Resource into the RUC, but that does not prevent the Resource from being committed in the RUC process like any other Resource that does not submit an offer in the RUC.

(4) For any hours in which the Resource is not RUC-committed, ERCOT shall consider all Three-Part Supply Offers in the RUC process until:

(a) The QSE withdraws the offer; or

(b) The offer expires by its terms.

4.4.9.2 Startup Offer and Minimum-Energy Offer

The Startup Offer component represents all costs incurred by a Generation Resource in starting up and reaching breaker close, as indicated by a telemetered Resource status of On-Line. The Minimum-Energy Offer component represents a proxy for the costs incurred by a Resource in producing energy up to and including the Resource's LSL after breaker close, as indicated by a telemetered Resource status of On-Line.

4.4.9.2.1 Startup Offer and Minimum-Energy Offer Criteria

(1) Each Startup Offer and Minimum-Energy Offer must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) The Resource's hot, intermediate, and cold Startup Offer in dollars;

(d) The Resource's Minimum-Energy Offer in dollars per MWh;

(e) The first and last hour of the Startup and Minimum-Energy Offers

(f) The expiration time and date of the offer;

(g) Percentage of FIP to the extent that the startup and minimum energy will be supplied by gas to determine the offer cap; and

(h) Percentage of FOP to the extent that the startup and minimum energy will be supplied by oil to determine the offer cap.

(2) Valid Startup Offers and Minimum-Energy Offers (which must be part of a Three-Part Supply Offer) must be received before 1000 for the effective DAM and DRUC.

(3) A QSE may update and submit a Three-Part Supply Offer for a Resource during the Adjustment Period for any hours in which the Resource is not RUC-committed before the offer is updated or submitted.

(4) The Resource's Startup Offer must be equal to or less than the Resource Category Generic Startup Cost for that type of Resource listed in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, unless ERCOT has approved verifiable Resource-specific startup costs for that Resource, under Section 4.4.9.2.4, Verifiable Startup Offer and Minimum-Energy Offer Caps, in which case the Resource's Startup Offer must be equal to or less than those approved verifiable Resource-specific startup costs.

(5) The Resource's Minimum-Energy Offer must be equal to or less than the Resource Category Generic Minimum-Energy Cost for that type of Resource listed in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, unless ERCOT has approved verifiable Resource-specific minimum-energy costs for that Resource, under Section 4.4.9.2.4, Verifiable Startup Offer and Minimum-Energy Offer Caps, in which case the Resource's Minimum-Energy Offer must be equal to or less than those approved verifiable Resource-specific minimum-energy costs.

4.4.9.2.2 Startup Offer and Minimum-Energy Offer Validation

(1) A valid Startup Offer and Minimum-Energy Offer is an offer that ERCOT has determined meets the criteria listed in Section 4.4.9.2.1, Startup Offer and Minimum-Energy Offer Criteria, and that are part of a Three-Part Supply Offer for which the Energy Offer Curve has also been validated.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any QSE submitting a Startup Offer and Minimum-Energy Offer to view its valid Startup Offers and Minimum-Energy Offers.

(3) ERCOT shall notify the QSE submitting a Startup Offer and Minimum-Energy Offer (which must be part of a Three-Part Supply Offer) if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the offer within the appropriate market timeline.

(4) Where a Split Generation Resource has submitted a Startup Offer and Minimum-Energy Offer, ERCOT shall validate the offers in accordance with Section 3.8, Special Considerations for Split Generation Meters.

4.4.9.2.3 Startup Offer and Minimum-Energy Offer Generic Caps

(1) The Resource Category Startup Offer Generic Cap, by applicable Resource category, is determined by the following O&M costs by Resource category:

Resource Category	**O&M Costs ($)**
Nuclear, Coal, Lignite, Hydro, Renewable	7,200
Combined Cycle greater than 90 MW with 5+ HRS off line	6,810
Combined Cycle greater than 90 MW with less than 5 HRS off line	5,310
Combined Cycle less than or equal to 90 MW with 5+ HRS off line	6,810
Combined Cycle less than or equal to 90 MW with less than 5 HRS off line	5,310
Gas steam supercritical boiler	4,800
Gas steam reheat boiler	3,000
Gas steam non-reheat or boiler w/o air-preheater	2,310
Simple cycle greater than 90 MW	5,000
Simple cycle less than or equal to 90 MW	2,300
Reciprocating Engines	1
RMR Resource	Not Applicable

(2) The Resource Category Minimum-Energy Generic Cap is the cost per MWh of energy for a Resource in producing energy up to and including the Resource's LSL after breaker close, as indicated by a telemetered Resource status of On-Line, according to the following:

(a) Hydro = $10.00/MWh;

(b) Coal and lignite = $18.00/MWh;

(c) Combined cycle greater than 90 MW = 10 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(d) Combined cycle less than or equal to 90 MW = 10 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(e) Gas steam supercritical boiler = 16.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(f) Gas steam reheat boiler = 17.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(g) Gas steam non-reheat or boiler without air-preheater = 19.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(h) Simple cycle greater than 90 MW = 15.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(i) Simple cycle less than or equal to 90 MW = 15.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in Minimum-Energy Offer;

(j) Reciprocating Engines = 16.0 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Minimum-Energy Offer;

(k) RMR Resource = RMR contract estimated fuel cost using its contract I/O curve at its LSL times FIP;

(l) Nuclear = Not Applicable; and

(m) Renewable = $0.

(3) The FIP and FOP used to calculate the Resource Category Minimum-Energy Generic Cap shall be the FIP or FOP for the Operating Day. In the event the Resource Category Minimum-Energy Generic Cap must be calculated before the FIP or FOP is available for the particular Operating Day, the FIP and FOP for the most recent preceding Operating Day shall be used. Once the FIP and FOP are available for a particular Operating Day, those values shall be used in the calculations. If the percentage fuel mix is not specified for Resource categories having the option to specify the fuel mix, then the minimum of FIP or FOP shall be used.

(4) Items (2)(c) and (2)(d) are determined by capacity of largest simple-cycle combustion turbine in the train.

4.4.9.2.4 Verifiable Startup Offer and Minimum-Energy Offer Caps

Once verifiable Resource-specific startup costs and minimum-energy costs are established and approved by ERCOT in accordance with Section 5.6.1, Verifiable Costs, then they are used in place of generic costs as described in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps. A QSE may file verifiable unit-specific costs for a Resource at any time, but it is not required to file those costs only because of a DAM commitment. The most recent approved verifiable costs on file must be used going forward.

4.4.9.3 Energy Offer Curve

(1) The "Energy Offer Curve" represents the QSE's willingness to sell energy at or above a certain price and at a certain quantity in the DAM or its willingness to be dispatched by SCED in Real-Time Operations.

(2) A QSE may submit Resource-specific Energy Offer Curves to ERCOT.

(3) Energy Offer Curves remain active for the offered period until either:

(a) Selected by ERCOT; or

(b) Automatically inactivated by the software at the offer expiration time selected by the QSE.

(4) For any hour that is not a RUC-Committed Interval or a DAM-Committed Interval for a Resource, the QSE for that Resource may submit or change Energy Offer Curves in the Adjustment Period and a QSE may withdraw an Energy Offer Curve if:

(a) An Output Schedule is submitted for all intervals for which an Energy Offer Curve is withdrawn, or

(b) The Resource is forced Off-Line and notifies ERCOT of the Forced Outage by changing the Resource Status appropriately and updating its COP.

(5) For any hour that is a RUC-Committed Interval or a DAM-Committed Interval for a Resource, a QSE for that Resource may not change an Energy Offer Curve, except as specified in (a) and (b) below:

(a) A QSE may change the Energy Offer Curve if the Resource is required, due to external fuel curtailments, to change fuel type or source during the Adjustment Period. ERCOT shall develop reasonable procedures for QSEs to report and document such fuel curtailments.

(b) A QSE may change the Energy Offer Curve if the Resource suffers a partial Forced Outage by truncating the Energy Offer Curve at the Resource's HSL as modified by the partial Forced Outage.

(6) If a valid Energy Offer Curve or an Output Schedule does not exist for a Resource that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period.

4.4.9.3.1 Energy Offer Curve Criteria

(1) Each Energy Offer Curve must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Resource represented by the QSE from which the offer would be supplied;

(c) A monotonically increasing offer curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs;

(d) The first and last hour of the Offer;

(e) The expiration time and date of the offer;

(f) List of Ancillary Service Offers from the same Resource;

(g) Inclusive or exclusive designation relative to other DAM offers; and

(h) Percentage of FIP and percentage of FOP for generation above LSL subject to the sum of the percentages not exceeding 100%.

(2) An Energy Offer Curve must be within the range of -$250.00 per MWh and the System-Wide Offer Cap in dollars per MWh. The software systems must be able to provide ERCOT with the ability to enter Resource-specific Energy Offer Curve floors and caps.

(3) The minimum amount per Resource for each Energy Offer Curve that may be offered is one MW.

4.4.9.3.2 Energy Offer Curve Validation

(1) A valid Energy Offer Curve is an offer curve that ERCOT has determined meets the criteria listed in Section 4.4.9.3.1, Energy Offer Curve Criteria, and the Energy Offer Curve that is part of a Three-Part Supply Offer for which the Startup Offer and Minimum-Energy Offer has also been validated.

(2) ERCOT shall notify the QSE submitting an Energy Offer Curve by the Messaging System if the offer was rejected or was considered invalid for any reason. The QSE may then resubmit the offer within the appropriate market timeline.

(3) ERCOT shall continuously validate Energy Offer Curves and continuously display on the MIS Certified Area information that allows any QSE to view its valid Energy Offer Curves.

4.4.9.3.3 Energy Offer Curve Caps for Make-Whole Calculation Purposes

(1) The following Energy Offer Curve Caps must be used for the purpose of Make-Whole Settlements:

(a) Nuclear = $15.00/MWh;

(b) Coal and Lignite = $18.00/MWh;

(c) Combined Cycle greater than 90 MW = 9 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(d) Combined Cycle less than or equal to 90 MW = 10 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(e) Gas -Steam Supercritical Boiler = 10.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(f) Gas Steam Reheat Boiler = 11.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(g) Gas Steam Non-reheat or boiler without air-preheater = 14.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(h) Simple Cycle greater than 90 MW = 14 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(i) Simple Cycle less than or equal to 90 MW = 15 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(j) Reciprocating Engines = 16 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(k) Hydro = $10.00/MWh;

(l) Other Renewable = $0/MWh; and

(m) RMR Resource = RMR contract price Energy Offer Curve.

(2) Items in (d) and (e) are determined by capacity of largest simple-cycle combustion turbine in the train selected.

(3) The FIP and FOP used to calculate the Energy Offer Curve Cap for Make-Whole Payment calculation purposes shall be the FIP or FOP for the Operating Day. In

the event the Energy Offer Curve Cap for Make-Whole Payment calculation purposes must be calculated before the FIP or FOP is available for the particular Operating Day, the FIP and FOP for the most recent preceding Operating Day shall be used. Once the FIP and FOP are available for a particular Operating Day, those values shall be used in the calculations. If the percentage fuel mix is not specified or if no Energy Offer Curve exists, then the minimum of FIP or FOP shall be used.

4.4.9.4 Mitigated Offer Cap and Mitigated Offer Floor

4.4.9.4.1 Mitigated Offer Cap

Energy Offer Curves may be subject to mitigation in Real-Time Operations under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Cap. The "Mitigated Offer Cap" is:

(a) For a Generation Resource that commences commercial operation after January 1, 2004, ERCOT shall construct an incremental mitigated offer cap curve (Section 6.5.7.3) such that each point on the Mitigated Offer Cap curve (Cap vs. output level) is the greater of:

(i) 14.5 MMBtu/MWh times the minimum of Fuel Index Price (FIP) or Fuel Oil Price (FOP); or

(ii) the Resource's verifiable incremental heat rate (MMBtu/MWh) for the output level multiplied by ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve, plus verifiable variable O&M cost ($/MWh) times a multiplier described in (c).

(b) For all other Generation Resources, each point on the Mitigated Offer Cap curve (Cap vs. output level) is the greater of:

(i) 10.5 MMBtu/MWh times the minimum of FIP or FOP; or

(ii) the Resource's verifiable incremental heat rate (MMBtu/MWh) for the output level multiplied by ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve, plus verifiable variable O&M cost ($/MWh) times a multiplier described in (c).

(c) The multipliers for Section 4.4.9.4.1, Mitigated Offer Cap, paragraphs (a)(ii) and (b)(ii) are as follows:

(i) 1.10 for Resources running at a $\geq$ 50% capacity factor for the previous 12 months;

(ii) 1.15 for Resources running at a $\geq$ 30 and < 50% capacity factor for the previous 12 months;

(iii) 1.20 for Resources running at a ≥ 20 and < 30% capacity factor for the previous 12 months;

(iv) 1.25 for Resources running at a ≥ 10 and < 20% capacity factor for the previous 12 months;

(v) 1.30 for Resources running at a ≥ 5 and < 10% capacity factor for the previous 12 months;

(vi) 1.40 for Resources running at a ≥ 1 and < 5% capacity factor for the previous 12 months; and

(vii) 1.50 for Resources running at a less than 1% capacity factor for the previous 12 months.

(d) The previous 12 months' capacity factor must be updated by ERCOT by the 20th day of each month using the most recent data for use in the next month. ERCOT shall post to the MIS Secure Area the capacity factor for each Resource before the start of the effective month.

(e) The process for developing the mitigate offer cap in (a) and (b) above must be described by ERCOT in a procedure approved by the appropriate TAC Subcommittee, and posted to the MIS Secure Area within one Business Day after initial approval, and after each approved change.

4.4.9.4.2 Mitigated Offer Floor

Energy Offer Curves may be subject to mitigation in Real-Time Market under Section 6.5.7.3, Security Constrained Economic Dispatch, using a Mitigated Offer Floor. The "Mitigated Offer Floor" is:

Resource Category	Mitigated Offer Floor
Nuclear and Hydro	-$250/MWh
Coal and Lignite	-$20/MWh
Combined Cycle	1 MMBtu/MWh * FIP
Gas/Oil Steam and Combustion Turbine	6 MMBtu/MWh * FIP or FOP, as specified in the Energy Offer Curve
QF	-$ 50/MWh
Wind	-$100/MWh
Other Renewables	-$ 50/MWh

4.4.9.5 DAM Energy-Only Offer Curves

(1) A QSE must submit any DAM Energy-Only Offer Curves by 1000 for the effective DAM.

(2) The DAM Energy-Only Offer Curve represents the QSE's willingness to sell energy at or above a certain price and at a certain quantity at a specific Settlement Point in the DAM. A DAM Energy-Only Offer Curve may be offered only in the DAM.

(3) DAM Energy-Only Offer Curves are not Resource-specific.

4.4.9.5.1 DAM Energy-Only Offer Curve Criteria

(1) Each DAM Energy-Only Offer Curve must be reported by a QSE and must include the following information:

(a) The selling QSE;

(b) The Settlement Point;

(c) The fixed quantity block, variable quantity block, or curve indicator for the offer;

(i) If a fixed quantity block, the single price (in $/MWh) and single quantity (in MW) for all hours offered in that block;

(ii) If a variable quantity block, the single price (in $/MWh) and single "up to" quantity (in MW) contingent on the purchase of all hours offered in that block; and

(iii) If a curve, a monotonically increasing energy offer curve for both price (in $/MWh) and quantity (in MW) with no more than ten price/quantity pairs;

(d) The first and last hour of the offer; and

(e) The expiration time and date of the offer.

(2) A DAM Energy-Only Offer Curve must be within the range of -$250.00 per MWh and the System-Wide Offer Cap in dollars per MWh.

(3) The minimum amount for each DAM Energy-Only Offer Curve that may be offered is one MW.

4.4.9.5.2 DAM Energy-Only Offer Validation

(1) A valid DAM Energy-Only Offer Curve is an offer that ERCOT has determined meets the criteria listed in Section 4.4.9.5.1, DAM Energy-Only Offer Curve Criteria.

(2) ERCOT shall notify the QSE submitting a DAM Energy-Only Offer Curve by the Messaging System if the offer was rejected or was considered invalid for any

reason. The QSE may then resubmit the offer within the appropriate market timeline.

(3) ERCOT shall continuously validate DAM Energy-Only Offers and continuously display on the MIS Certified Area information that allows any QSE to view its valid DAM Energy-Only Offers.

4.4.9.6 DAM Energy Bids

(1) A QSE must submit any DAM Energy Bids by 1000 for the effective DAM.

(2) A DAM Energy Bid represents the QSE's willingness to buy energy at or below a certain price and at a certain quantity at a specific Settlement Point in the DAM. A DAM Energy Bid may be made only in the DAM.

4.4.9.6.1 DAM Energy Bid Criteria

(1) Each DAM Energy Bid must be reported by a QSE and must include the following information:

(a) The buying QSE;

(b) The Settlement Point;

(c) Fixed quantity block, variable quantity block, or curve indicator for the bid;

(i) If a fixed quantity block, the single price (in $/MWh) and single quantity (in MW) for all hours bid in that block;

(ii) If a variable quantity block, the single price (in $/MWh) and single "up to" quantity (in MW) contingent on the purchase of all hours bid in that block; and

(iii) If a curve, a monotonically decreasing energy bid curve for both price (in $/MWh) and quantity (in MW) with no more than 10 price/quantity pairs.

(d) The first and last hour of the bid; and

(e) The expiration time and date of the bid.

(2) The minimum amount for each DAM Energy Bid that may be bid is one MW.

4.4.9.6.2 DAM Energy Bid Validation

(1) A valid DAM Energy Bid is a bid that ERCOT has determined meets the criteria listed in Section 4.4.9.6.1, DAM Energy Bid Criteria.

(2) ERCOT shall notify the QSE submitting a DAM Energy Bid by the Messaging System if the bid was rejected or was considered invalid for any reason. The QSE may then resubmit the bid within the appropriate market timeline.

(3) ERCOT shall continuously validate DAM Energy Bids and continuously display on the MIS Certified Area information that allows any QSE to view its valid DAM Energy Bids.

4.4.10 Credit Requirement for DAM Bids and Offers

(1) Each QSE's ability to bid and offer in the DAM is subject to credit exposure from the QSE's bids and offers being within the credit limit for DAM participation established for the entire Counter-Party of which the QSE is part, as specified in item (1) of Section 16.11.4.6.2, Credit Requirements for DAM Participation, and taking into account the credit exposure of accepted DAM bid and offers of the Counter-Party's other QSEs.

(2) DAM bids and offers of all QSEs of the Counter-Party are accepted in the order submitted while ensuring that the credit exposure from accepted bids and offers do not exceed the Counter-Party's credit limit for DAM participation.

(3) ERCOT shall reject the QSE's individual bids and offers whose credit exposure, as calculated in item (6) below, exceeds the Counter-Party's credit limit for DAM participation as described in items (1) and (2) above, and shall notify the QSE through the MIS Certified Area as soon as practicable.

(4) The QSE may revise and resubmit such rejected bids and offers described in item (3) above, provided that the resubmitted bids and offers are valid and within the Counter-Party's credit limit for DAM participation adjusted for all accepted DAM bids and offers of the Counter-Party's QSE's limit and that such resubmission occurs prior to 1000 of the Operating Day.

(5) DAM shall use the Counter-Party's credit limit for DAM participation provided on the most recent Business Day and adjusted for accepted bids and offers for markets cleared, until a new credit limit for DAM participation is available.

(6) ERCOT shall calculate credit exposure for bids and offers in the DAM as follows:

(a) For each DAM Energy Bid, the quantity of the bid multiplied by the bid price.

(b) For each DAM Energy Offer, the product of the quantity of the offer times the 95th percentile of the hourly difference of Real-Time Settlement Point Price and Day-Ahead Settlement Point Price over the previous 30 days for the hour.

(c) For DAM Energy Bids and Offers at the same Settlement Point for the same hour ERCOT shall calculate the credit exposure as the maximum of the credit exposure for the DAM Energy Bid as calculated in item (a) or the credit exposure for the DAM Energy Offer as calculated in item (b) above.

(d) For PTP Obligation Bids, the sum of the quantity of bid multiplied by the bid price, if positive, plus 95th percentile of the hourly positive price difference between the source Real-Time Settlement Point Price minus the sink Real-Time Settlement Point Price over the previous 30 days for the hour.

(e) For Ancillary Services not self-arranged, the product of the quantity of Ancillary Service not self-arranged times the 95th percentile of the hourly MCPC for that Ancillary Service over the previous 30 days for that hour.

4.4.11 System-Wide Offer Caps

(1) The System-Wide Offer Cap (SWCAP) is as follows:

(a) The low system-wide offer cap (LCAP) is set on a daily basis at the higher of:

(i) $500 per MWh for energy and $500 per MW per hour for Ancillary Services; or

(ii) Fifty times the Fuel Index Price (FIP) of the previous Operating Day, expressed in dollars per MWh for energy and dollars per MW per hour for Ancillary Services.

(b) The high system-wide offer cap (HCAP) is $2,250 per MWh for energy and $2,250 per MW per hour for Ancillary Services.

(c) Beginning two months after nodal implementation, the HCAP shall be $3,000 per MWh for energy and $3,000 per MW per hour for Ancillary Services.

(d) At the beginning of each annual resource adequacy cycle, the SWCAP shall be set equal to the HCAP and maintained at this level as long as the peaker net margin (PNM) during an annual resource adequacy cycle is less than or equal to $175,000 per MW. During an annual resource adequacy cycle, the SWCAP shall be as set forth above in items (b) and (c) above, unless the PNM has exceeded $175,000 per MW by the date specified. If the PNM exceeds $175,000 per MW during an annual resource adequacy cycle, on the next Operating Day, the SWCAP shall be reset to the LCAP for the remainder of that annual resource adequacy cycle.

(2) Any offers that exceed the current SWCAP shall be rejected by ERCOT.

4.4.11.1 Scarcity Pricing Mechanism

(1) ERCOT shall operate the scarcity pricing mechanism (SPM) as follows:

(a) The SPM operates on an annual resource adequacy cycle, starting on January 1 and ending on December 31 of each year.

(b) For each day of the annual resource adequacy cycle, the peaking operating cost (POC) shall be ten times the FIP for the previous Operating Day. The POC is calculated in dollars per megawatt-hour (MWh).

(c) For the purpose of this Section, the Real-Time energy price (RTEP) shall be measured as the ERCOT Hub Average 345 kV Hub price.

(d) For the current annual resource adequacy cycle, the PNM shall be calculated in dollars per megawatt (MW) on a cumulative basis for all past intervals in the annual resource adequacy cycle as follows:

∑((RTEP – POC) * (.25)) for each settlement interval where (RTEP – POC) >0

(e) By the end of the next Business Day following the applicable Operating Day, ERCOT shall post the updated value of the PNM and the current SWCAP on the MIS Public Area.

4.5 DAM Execution and Results

4.5.1 DAM Clearing Process

(1) At 1000 in the Day-Ahead, ERCOT shall start the DAM clearing process.

(2) Prior to execution of the DAM, ERCOT shall complete a Day-Ahead Simultaneous Feasibility Test. This test uses the Day-Ahead Updated Network Model topology and evaluates all CRRs for feasibility to determine hourly oversold quantities.

(3) The purpose of the DAM is to economically and simultaneously clear offers and bids described in Section 4.4, Inputs into DAM and Other Trades.

(4) The DAM uses a multi-hour mixed integer programming algorithm to maximize bid-based revenues minus the offer-based costs over the Operating Day, subject to security and other constraints, and ERCOT Ancillary Service procurement requirements.

(a) The bid-based revenues include revenues from DAM Energy Bids and PTP Obligation Bids.

(b) The offer-based costs include costs from the Startup Offer, Minimum Energy Offer, and Energy Offer Curve of any Resource that submitted a Three-Part Supply Offer, DAM Energy-Only Offers, CRR Offers, and Ancillary Service Offers.

(c) Security constraints specified to prevent DAM solutions that would overload the elements of the ERCOT Transmission Grid include the following:

(i) Transmission constraints – Transfer limits on energy flows through the ERCOT Transmission Grid, e.g., thermal or stability limits. These limits must be satisfied by the intact network and for certain specified contingencies.

These constraints may represent:

(A) Thermal constraints – protect transmission facilities against thermal overload.

(B) Generic constraints – protect the ERCOT Transmission Grid against transient instability, dynamic stability or voltage collapse.

(C) Power flow constraints – the energy balance at required Electrical Buses in the ERCOT Transmission Grid must be maintained.

(ii) Resource constraints – the physical and security limits on Resources that submit Three-Part Supply Offers:

(A) Resource output constraints – the LSL and HSL of each Resource, and

(B) Resource operational constraints – includes minimum run time, minimum down time, and configuration constraints.

(iii) Other constraints –

(A) Linked offers –the DAM may not select any one part of that Resource capacity to provide more than one Ancillary Service or to provide both energy and an Ancillary Service in the same Operating Hour. The DAM may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service or energy in the same Operating Hour.

(B) The sum of the awarded Ancillary Service capacities for each Resource must be within the Resource limits specified in COP and Section 3.18, Resource Limits in Providing Ancillary Service, and the Resource parameters as described in Section 3.7, Resource Parameters.

(C) Block Ancillary Service Offers for a Load Resource– blocks will not be cleared unless the entire quantity block can be awarded.

(D) Block CRR Offers and PTP Obligation Bids- blocks will not be cleared unless the entire time block can be awarded.

(d) Ancillary Service needs for each Ancillary Service include the needs specified in the Ancillary Service Plan that are not part of the Self-Arranged Ancillary Service Quantity and that must be met from available DAM Ancillary Service Offers while co-optimizing with DAM Energy Offers. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service. See Section 4.5.2, Ancillary Service Insufficiency, for what happens if insufficient Ancillary Service Offers are received in the DAM.

(5) ERCOT shall determine the appropriate Load distributions to allocate offers, bids, and source and sink of CRRs at a Load Zone across the Electrical Buses that are modeled with Load in that Load Zone. The default distribution is the State Estimator hourly distribution for the seven days before the Operating Day. If ERCOT decides, in its sole discretion, to change this distribution for reasons such as anticipated weather events or holidays, ERCOT shall select a State Estimator distribution from a proxy day reasonably reflecting the anticipated distribution in the Operating Day. ERCOT may also modify this distribution to account for predicted differences in network topology between the proxy day and Operating Day. ERCOT shall develop a methodology, subject to TAC approval to describe the modification of the proxy day bus-load distribution for this purpose.

(6) ERCOT shall allocate offers, bids, and source and sink of CRRs at a Hub using the distribution factors specified in the definition of that Hub in Section 3.5.2, Hub Definitions.

(7) A Resource that has a Three-Part Supply Offer cleared in the DAM may be eligible for make whole payment of the Startup Offer and Minimum Energy Offer submitted by the QSE representing the Resource under Section 4.6, DAM Settlement.

(8) The directional network element flows for PTP Options declared for settlement in Real-Time must be properly accounted for in determining available transmission network capacity in the DAM. In the event the available transmission capability in the DAM cannot accommodate all PTP Options declared for settlement in Real-Time, any PTP Option declared for settlement in Real-Time that impacts overloaded directional network elements must be appropriately derated for DAM modeling purposes only, in proportion to that impact. The derated MW of PTP Options declared for settlement in Real-Time will be settled in the DAM if their Minimum Reservation Prices are less than or equal to the DAM prices for

corresponding PTP Options. Otherwise, the derated MW will be settled in Real-Time.

(9) The DAM settlement is based on hourly MW awards and on Day-Ahead hourly Settlement Point Prices. All PTP Options settled in the DAM are settled based on the Day-Ahead Settlement Point Prices.

(10) The Day-Ahead Market Clearing Price for Capacity (MCPC) for each hour for each Ancillary Service is the Shadow Price for that Ancillary Service for the hour as determined by the DAM algorithm.

(11) If the Day-Ahead MCPC cannot be calculated by ERCOT, the Day-Ahead MCPC for the particular Ancillary Service is equal to the Day-Ahead MCPC for that Ancillary Service in the same Settlement Interval of the preceding Operating Day.

(12) If the Day-Ahead Settlement Point Prices cannot be calculated by ERCOT, all CRRs shall be settled based on Real-Time Prices. Settlements for all CRRs shall be reflected on the RT Settlement Statement.

4.5.2 Ancillary Service Insufficiency

(1) ERCOT shall determine if there is an insufficiency in Ancillary Service Offers before executing the DAM. If ERCOT receives insufficient Ancillary Service Offers in the DAM to procure one or more required Ancillary Service such that the Ancillary Service Plan is deficient and system security and reliability is threatened:

(a) ERCOT shall declare an Ancillary Service insufficiency and issue an Alert under Section 6.5.9.3.3, Alert.

(b) ERCOT shall request additional Ancillary Service Offers.

(i) A QSE may resubmit an offer for an Ancillary Service that it submitted before the Alert for the same Ancillary Service, but the resubmitted offer must meet the following criteria to be considered a valid offer:

(A) The offer quantity may not be less than the offer quantity submitted before the Alert, unless the portion of the offer not resubmitted was priced higher than the portion of the offer that is being resubmitted; and

(B) For the amount of the offer quantity that is not more than the offer quantity submitted before the Alert, the offer must be priced equal to or less than the price of the offer submitted before the Alert.

(ii) For any amount of the offer that is greater in quantity than the QSE's offer that was not submitted before the Alert, the incremental amount of the offer may be submitted at a price subject to the offer cap.

(c) ERCOT shall not begin executing the DAM sooner than 30 minutes after issuing the Alert. If the additional Ancillary Service Offers are still insufficient to supply the Ancillary Service required in the Day-Ahead Ancillary Service Plan then ERCOT shall run the DAM by reducing the Ancillary Service Plan quantities only for purposes of the DAM by the amount of insufficiency.

(d) When ERCOT must reduce the Ancillary Service Plan for purposes of the DAM due to insufficient Ancillary Service Offers, ERCOT shall preserve the Ancillary Service Plan in the DAM in the following order of priority:

(i) Reg-Up;

(ii) Reg-Down;

(iii) RRS; and

(iv) Non-Spin.

(2) ERCOT shall procure the difference in capacity between the Day-Ahead Ancillary Service Plan and the DAM-reduced Ancillary Service Plan amounts using the DRUC from Resources that are qualified to provide the needed Ancillary Service.

4.5.3 Communicating DAM Results

(1) As soon as practicable, but no later than 1330 in the Day-Ahead, ERCOT shall notify the parties to each cleared DAM transaction (e.g., the buyer and the seller) of the results of the DAM as follows:

(a) Awarded Ancillary Service Offers, specifying Resource, MW, Ancillary Service Type, and price, for each hour of the awarded offer;

(b) Awarded energy offers from Three-Part Supply Offers and from DAM Energy-Only Offers, specifying Resource (except for DAM Energy-Only Offers), MWh, Settlement Point, and Settlement Point Price, for each hour of the awarded offer;

(c) Awarded DAM Energy Bids, specifying MWh, Settlement Point, and Settlement Point Price for each hour of the awarded bid;

(d) Awarded CRR Offers (PTP Options and PTP Options with Refund), specifying CRR identifier(s), number of CRRs in MW, source and sink

Settlement Points, and price, for each Settlement Interval of the awarded offer; and

(e) Awarded PTP Obligation Bids, number of PTP Obligations in MW, source and sink Settlement Points, and price for each Settlement Interval of the awarded bid.

(2) As soon as practicable, but no later than 1330, ERCOT shall post on the MIS Public Area the hourly:

(a) Day-Ahead MCPC for each type of Ancillary Service for each hour of the Operating Day;(b) Day-Ahead Settlement Point Prices for each Settlement Point for each hour of the Operating Day;

(c) Day-Ahead hourly LMPs for each Electrical Bus for each hour of the Operating Day;

(d) Shadow Prices for every binding constraint for each hour of the Operating Day;

(e) Quantity of total Ancillary Service Offers received in the DAM, in MW by Ancillary Service type for each hour of the Operating Day;

(f) Total quantity of energy (in MWh) bought in DAM at each Settlement Point for each hour of the Operating Day;

(g) Total quantity of energy (in MWh) sold in the DAM at each Settlement Point for each hour of the Operating Day; and

(h) Aggregated Ancillary Service Offer Curve of all Ancillary Service Offers for each type of Ancillary Service for each hour of the Operating Day.

(3) ERCOT shall monitor Day-Ahead MCPCs and Day-Ahead hourly LMPs for errors and shall “flag” for further review questionable prices before posting and make notations in the posting if there are conditions that cause the price to be questionable.

(4) All DAM LMPs, MCPCs, and Settlement Point Prices are final at 1000 of the next Business Day after the Operating Day. After DAM LMPs, MCPCs, and Settlement Point Prices are final, they cannot be changed unless the Board finds that the DAM LMPs, MCPCs, or Settlement Point Prices are significantly affected by a software or data error.

4.6 DAM Settlement

4.6.1 Day-Ahead Settlement Point Prices

4.6.1.1 Day-Ahead Settlement Point Prices for Resource Nodes

The Day-Ahead Settlement Point Price (DASPP) for a Resource Node Settlement Point for an hour is the Locational Marginal Price (LMP) at that Resource Node for that hour as calculated in the Day-Ahead Market (DAM) process.

4.6.1.2 Day-Ahead Settlement Point Prices for Load Zones

The DASPP for a Load Zone Settlement Point for an hour is calculated as follows:

$$\textbf{DASPP} = \sum_{b} (\textbf{DADF}_{b} * \textbf{DALMP}_{b})$$

The above variables are defined as follows:

Variable	Unit	Definition
DASPP	\$/MWh	*Day-Ahead Settlement Point Price*—The DAMSPP at the Settlement Point for the hour.
$DALMP_b$	\$/MWh	*Day-Ahead Locational Marginal Price per bus*—The DAM LMP at Electrical Bus *b* for the hour.
$DADF_b$	none	*Day-Ahead Distribution Factor per bus*—The Load distribution factor, as described in Section 4.5.1, DAM Clearing Process, for Electrical Bus *b* in the Load Zone for the hour.
b	none	An Electrical Bus that is assigned to the Load Zone.

4.6.1.3 Day-Ahead Settlement Point Prices for Hubs

The DASPP for a Settlement Point at a Hub is determined according to the methodology included in the definition of that Hub in Section 3.5, Hubs.

4.6.2 Day-Ahead Energy and Make-Whole Settlement

4.6.2.1 Day-Ahead Energy Payment

(1) The Day-Ahead Energy Payment is made for all cleared offers (excluding offers submitted for the Reliability Must-Run (RMR) Units) to sell energy in the DAM, whether through Three-Part Supply Offers or DAM Energy-Only Offer Curves. The payment to each Qualified Scheduling Entity (QSE) for each Settlement Point for a given hour of the Operating Day is calculated as follows:

$$\textbf{DAESAMT}_{q,p} = (-1) * \textbf{DASPP}_{p} * \textbf{DAES}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Definition

DAESAMT $_{q, p}$	$	*Day-Ahead Energy Sale Amount per QSE per Settlement Point*—The payment to QSE *q* for the cleared energy offers at Settlement Point *p* for the hour.
DASPP $_{p}$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM SPP at Settlement Point *p* for the hour.
DAES $_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves at Settlement Point *p*, excluding the offers submitted for RMR Units at the same Settlement Point, for the hour.
q	none	A QSE.
p	none	A Settlement Point.

(2) The total of the Day-Ahead Energy Payments to each QSE for the hour is calculated as follows:

$$\textbf{DAESAMTQSETOT}_{q} = \sum_{p} \textbf{DAESAMT}_{q, p}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAESAMTQSETOT $_{q}$	$	*Day-Ahead Energy Sale Amount QSE Total per QSE*—The total of the payments to QSE *q* for its cleared energy offers at all Settlement Points for the hour.
DAESAMT $_{q, p}$	$	*Day-Ahead Energy Sale Amount per QSE per Settlement Point*—The payment to QSE *q* for the cleared energy offers at Settlement Point *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.

4.6.2.2 Day-Ahead Energy Charge

(1) The Day-Ahead Energy Charge is made for all cleared DAM Energy Bids. This charge to each QSE for each Settlement Point for a given hour of the Operating Day is calculated as follows:

$$\textbf{DAEPAMT}_{q, p} = \textbf{DASPP}_{p} * \textbf{DAEP}_{q, p}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAEPAMT $_{q, p}$	$	*Day-Ahead Energy Charge per QSE per Settlement Point*—The charge to QSE *q* for all its cleared DAM Energy Bids at Settlement Point *p* for the hour.
DASPP $_{p}$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM SPP at Settlement Point *p* for the hour.
DAEP $_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared DAM Energy Bids at Settlement Point *p* for the hour.

Variable	Unit	Definition
q	none	A QSE.
p	none	A Settlement Point.

(2) The total of the Day-Ahead Energy Charges to each QSE for the hour is calculated as follows:

$$\mathbf{DAEPAMTQSETOT}_{\boldsymbol{q}} = \sum_{p} \mathbf{DAEPAMT}_{\boldsymbol{q, p}}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DAEPAMTQSETOT_{q}$	$	*Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total of the charges to QSE *q* for its cleared DAM Energy Bids at all Settlement Points for the hour.
$DAEPAMT_{q, p}$	$	*Day-Ahead Energy Purchase Amount per QSE per Settlement Point*—The charge to QSE *q* for its cleared DAM Energy Bids at Settlement Point *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.

4.6.2.3 Day-Ahead Make-Whole Settlements

(1) A QSE that has a Three-Part Supply Offer cleared in the DAM is eligible for a Day-Ahead Make-Whole Payment startup cost compensation, if, for the Resource associated with the offer:

(a) The generator's breakers were open, as indicated by a telemetered Resource status of Off-Line, for at least five minutes during the Adjustment Period for the beginning of the DAM commitment;

(b) The generator's breakers were closed, as indicated by a telemetered Resource status of On-Line, for at least one minute during the DAM commitment period; and

(c) The breaker open-close sequence, as indicated by the On-Line/Off-Line sequence from the telemetered Resource status, for which the QSE is eligible for startup cost compensation in the DAM or Reliability Unit Commitment (RUC) for the previous Operating Day does not qualify in meeting the criteria in items (a) and (b) above.

(d) The breaker open-close sequence for which the QSE is eligible for startup cost compensation in an earlier DAM commitment period within the same Operating Day does not qualify in meeting the criteria in items (a) and (b) above.

(2) A QSE that has a Three-Part Supply Offer cleared in the DAM is eligible for Day-Ahead Make-Whole Payment energy cost compensation in a DAM-committed Operating Hour, if, for the Resource associated with the offer the generator's breakers were closed for at least one minute during the DAM-committed Operating Hour.

(3) The Day-Ahead Make-Whole Payment guarantees the QSE that the total payment received from the DAM for a DAM-committed Resource is not less than the total cost calculated based on the Startup Offer, the Minimum Energy Offer, and the Energy Offer Curve capped by the Energy Offer Curve Cap defined under Section 4.4.9.3.3, Energy Offer Curve Caps for Make-Whole Calculation Purposes.

(4) If a Generation Resource is eligible for startup or energy cost compensation in the Day-Ahead Make-Whole payment, then Ancillary Service revenue from the hours committed in the Day-Ahead Market will be included in its Make-Whole calculation for that Resource.

4.6.2.3.1 Day-Ahead Make-Whole Payment

(1) ERCOT shall pay the QSE a Day-Ahead Make-Whole Payment for an eligible Resource, except that the Day-Ahead Make-Whole RMR Revenue amount is calculated but not paid for any RMR Unit, for each Operating Hour in a DAM-commitment period.

(2) Any Ancillary Service Offer cleared for the same Operating Hour, QSE, and Generation Resource as a Three-Part Supply Offer cleared in the DAM shall be included in the calculation of the Day-Ahead Make-Whole Payment.

(3) The Day-Ahead Make-Whole Payment to each QSE for each DAM-committed Generation Resource (excluding RMR units) is calculated as follows:

$$\mathbf{DAMWAMT}_{q,p,r,h} = (-1) * \mathbf{Max}\,(0, \mathbf{DAMGCOST}_{q,p,r} + \sum_{h} \mathbf{DAEREV}_{q,p,r,h} + \sum_{h} \mathbf{DAASREV}_{q,r,h}) * \mathbf{DAESR}_{q,p,r,h} / (\sum_{h} \mathbf{DAESR}_{q,p,r,h})$$

Where:

$$\text{DAMGCOST}_{q,p,r} = \text{SUO}_{q,p,r} + \sum_{h} (\text{MEO}_{q,p,r,h} * \text{LSL}_{q,p,r,h}) + \sum_{h} (\text{DAAIEC}_{q,p,r,h} * (\text{DAESR}_{q,p,r,h} - \text{LSL}_{q,p,r,h}))$$

$$\text{DAEREV}_{q,p,r,h} = (-1) * \text{DASPP}_{p,h} * \text{DAESR}_{q,p,r,h}$$

$$\text{DAASREV}_{q,r,h} = ((-1) * \text{MCPCRU}_{DAM,h} * \text{PCRUR}_{r,q,DAM,h}) +$$

$((-1) * MCPCRD_{DAM,\, h} * PCRDR_{r,\, q, DAM,\, h}) +$

$((-1) * MCPCRR_{DAM,\, h} * PCRRR_{r,\, q, DAM,\, h}) +$

$((-1) * MCPCNS_{DAM,\, h} * PCNSR_{r,\, q, DAM,\, h})$

(4) The Day-Ahead Make-Whole RMR Revenue for each QSE for each DAM-committed RMR Unit is calculated as follows:

$$\mathbf{DAMWRMRREV}_{q,\, p, r,\, h} = \mathbf{(-1) * Max\ (0, DAMGCOST}_{q,\, p,\, r} + \sum_{h} \mathbf{DAEREV}_{q,\, p,\, r,\, h} + \sum_{h} \mathbf{DAASREV}_{q,\, r,\, h}\mathbf{) * DAESR}_{q,\, p,\, r,\, h}\ /\ (\sum_{h} \mathbf{DAESR}_{q,\, p,\, r,\, h})$$

Where:

$$DAMGCOST_{q,\, p,\, r} = SUO_{q,\, p,\, r} + \sum_{h} (MEO_{q,\, p,\, r,\, h} * LSL_{q,\, p,\, r,\, h}) + \sum_{h} (DAAIEC_{q,\, p,\, r,\, h} * (DAESR_{q,\, p,\, r,\, h} - LSL_{q,\, p,\, r,\, h}))$$

$$DAEREV_{q,\, p,\, r,\, h} = (-1) * DASPP_{p,\, h} * DAESR_{q,\, p,\, r,\, h}$$

$$DAASREV_{q,\, r,\, h} = ((-1) * MCPCRU_{DAM,\, h} * PCRUR_{r,\, q,\, DAM,\, h}) + ((-1) * MCPCRD_{DAM,\, h} * PCRDR_{r,\, q, DAM,\, h}) + ((-1) * MCPCRR_{DAM,\, h} * PCRRR_{r,\, q, DAM,\, h}) + ((-1) * MCPCNS_{DAM,\, h} * PCNSR_{r,\, q, DAM,\, h})$$

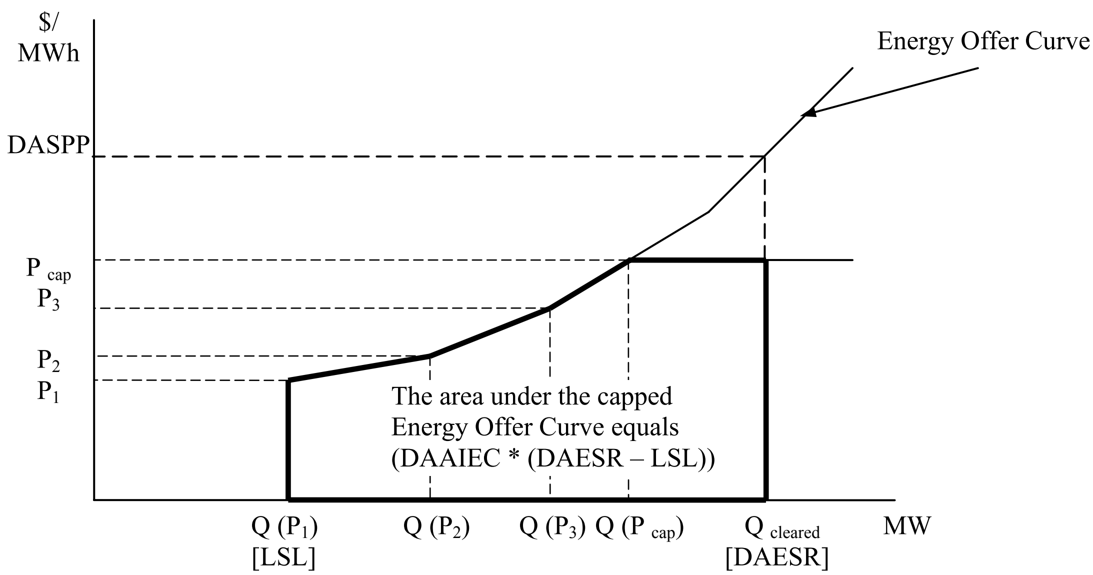
The above variables are defined as follows:

Variable	Unit	Definition
$DAMWAMT_{q,\, p,\, r,\, h}$	$	*Day-Ahead Make-Whole Payment per QSE per Settlement Point per Resource per hour* — The payment to QSE *q* to make-whole the Startup Cost and Energy Cost of Resource *r* committed in the DAM at Resource Node *p* for the hour *h*.
$DAMWRMRREV_{q,\, p,\, r,\, h}$	$	*Day-Ahead Make-Whole RMR Revenue per QSE per Settlement Point, per RMR Resource, per hour* — The revenue calculated but not paid to QSE *q* to make-whole the Startup Cost and Energy Cost of the RMR Resource r committed in the DAM at Resource Node *p* for the hour *h*.
$DAMGCOST_{q,\, p,\, r}$	$	*Day-Ahead Market Guaranteed Amount per QSE per Settlement Point per Resource*— The sum of the startup cost and the operating energy costs of the DAM-committed Resource *r* at Resource Node *p* represented by QSE *q*, for the DAM-commitment period.
$DAEREV_{q,\, p,\, r,\, h}$	$	*Day-Ahead Energy Revenue per QSE per Settlement Point per Resource by hour* — The revenue received in the DAM for Resource *r* at Resource Node *p* represented by QSE *q*, based on the DAM Settlement Point Price, for the hour *h*.

Variable	Unit	Definition
DAASREV $_{q,\ r,\ h}$	$	*Day-Ahead Ancillary Service Revenue per QSE per Resource by hour*— The revenue received in the DAM for Resource *r* represented by QSE *q*, based on the Market Clearing Price for Capacity (MCPC) for each Ancillary Service in the DAM, for the hour *h*.
DASPP $_{p,\ h}$	$/MWh	*Day-Ahead Settlement Point Price by Settlement Point by hour*— The DAM Settlement Point Price at Resource Node *p* for the hour *h*.
DAESR $_{q,\ p,\ r,\ h}$	MW	*Day-Ahead Energy Sale from Resource per QSE by Settlement Point per Resource by hour* — The amount of energy cleared through Three-Part Supply Offers in the DAM for Resource *r* at Resource Node *p* represented by QSE *q* for the hour *h*.
PCRUR $_{r,\ q,\ DAM}$	MW	*Procured Capacity for Reg-Up from Resource per Resource per QSE in DAM*—The Regulation Up (Reg-Up) capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour.
MCPCRU $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up in DAM*—The DAM MCPC for Reg-Up for the hour.
PCRDR $_{r,\ q,\ DAM}$	MW	*Procured Capacity for Reg-Down from Resource per Resource per QSE in DAM*—The Regulation Down (Reg-Down) capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour.
MCPCRD $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down in DAM*—The DAM MCPC for Reg-Down for the hour.
PCRRR $_{r,\ q,\ DAM}$	MW	*Procured Capacity for Responsive Reserve from Resource per Resource per QSE in DAM*—The Responsive Reserve capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour.
MCPCRR $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for Responsive Reserve for the hour.
PCNSR $_{r,\ q,\ DAM}$	MW	*Procured Capacity for Non-Spin from Resource per Resource per QSE in DAM*—The Non-Spin capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour.
MCPCNS $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin in DAM*—The DAM MCPC for Non-Spin for the hour.
SUO $_{q,\ p,\ r}$	$/start	*Startup Offer per QSE per Settlement Point per Resource*—The Startup Offer included in the Three-Part Supply Offer associated with Resource *r* at Resource Node *p* represented by QSE *q*, for the first hour of the DAM-commitment period.
MEO $_{q,\ p,\ r,\ h}$	$/MWh	*Minimum-Energy Offer per QSE per Settlement Point per Resource per hour*—The Minimum-Energy Offer included in the Three-Part Supply Offer associated with Resource *r* at Resource Node *p* represented by QSE *q*, for the hour *h*.
LSL $_{q,\ p,\ r,\ h}$	MW	*Low Sustained Limit per QSE per Settlement Point per Resource per hour*—The Low Sustained Limit (LSL) of Resource *r* at Resource Node *p* represented by QSE *q*, for the hour *h*.
DAAIEC $_{q,\ p,\ r\ h}$	$/MWh	*Day-Ahead Average Incremental Energy Cost per QSE per Settlement Point per Resource per hour*—The average incremental energy cost, calculated according to the Energy Offer Curve capped by the generic energy price, for the output levels between the DAESR and the LSL of Resource *r* at Resource Node *p* represented by QSE *q*, for the hour *h*.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A DAM-committed Generation Resource.

Variable	Unit	Definition
h	none	An hour in the DAM-commitment period.

(5) The calculation of the Day-Ahead Average Incremental Energy Cost for each Resource for each hour is illustrated with the picture below, where P_{cap} is the Energy Offer Curve Cap. The method to calculate such cost is described in Section 4.6.5, Calculation of "Average Incremental Energy Cost" (AIEC).

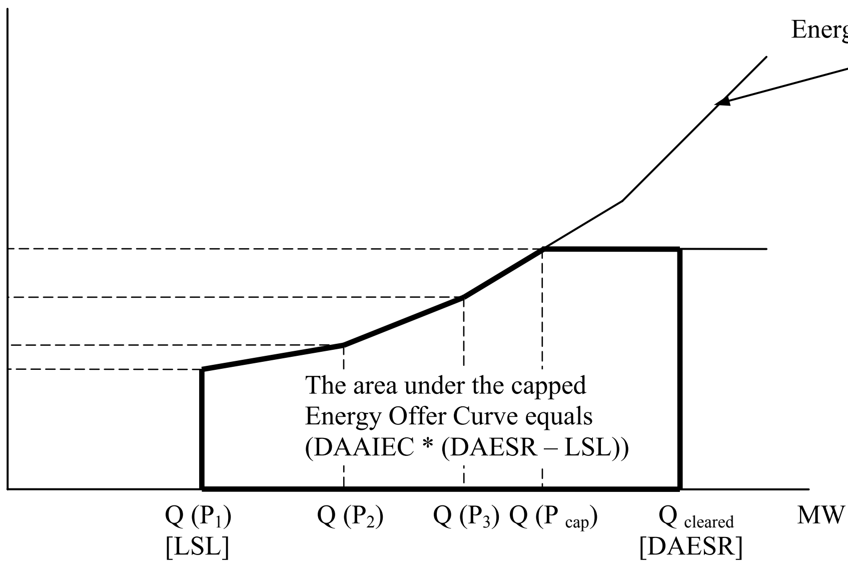


(6) The total of the Day-Ahead Make-Whole Payments to each QSE for non-RMR Generation Resources for a given hour is calculated as follows:

$$\textbf{DAMWAMTQSETOT}_{q} = \sum_{p} \sum_{r} \textbf{DAMWAMT}_{q,\,p,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAMWAMTQSETOT $_{q}$	$	*Day-Ahead Make-Whole Payment QSE Total per QSE*—The total of the Day-Ahead Make-Whole Payments to QSE *q* for the DAM-committed non-RMR Generation Resources represented by this QSE for the hour.
DAMWAMT $_{q, p, r}$	$	*Day-Ahead Make-Whole Payment per QSE per Settlement Point per Resource*—The payment to QSE *q* to make-whole the Startup Cost and Energy Cost of Resource *r* committed in the DAM at Resource Node *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A DAM-committed non-RMR Generation Resource.



(7) The total of the Day-Ahead Make-Whole RMR Revenue for each QSE for RMR Units for a given hour is calculated as follows:

$$\textbf{DAMWRMRREVQSETOT}_{q} = \sum_{p}\sum_{r} \textbf{DAMWRMRREV}_{q,\,p,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAMWRMRREVQSETOT $_{q}$	$	*Day-Ahead Make-Whole RMR Revenue QSE Total per QSE*—The total of the Day-Ahead Make-Whole Revenue calculated for QSE *q* for DAM-committed RMR Units represented by this QSE for the hour.
DAMWRMRREV $_{q, p, r,}$	$	*Day-Ahead Make-Whole RMR Revenue per QSE per Settlement Point, per RMR Resource, per hour*—The revenue calculated but not paid to QSE *q* to make-whole the Startup Cost and Energy Cost of the RMR Resource *r* committed in the DAM at Resource Node *p* for the hour.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A DAM-committed RMR Unit.

4.6.2.3.2 Day-Ahead Make-Whole Charge

ERCOT shall charge a Day-Ahead Make-Whole Charge to each QSE that has one or more cleared DAM Energy Bids and/or Point-to-Point (PTP) Obligation Bids. The Day-Ahead Make-Whole Charge for an hour is that QSE's prorata share of the total amount of Day-Ahead Make-Whole Payments and Day-Ahead Make-Whole RMR Revenue for that hour. The proration must be based on the ratio of the energy amount of the QSE's cleared DAM Energy Bids and PTP Obligation Bids to the total energy amount of all QSEs' cleared DAM Energy Bids and PTP Obligation Bids. The Day-Ahead Make-Whole Charge to each QSE for a given hour is calculated as follows:

$$\mathbf{LADAMWAMT}_{q} = \mathbf{(-1) * (DAMWAMTTOT + RMRDAMWREVTOT) * DAERS}_{q}$$

Where:

Day-Ahead Make-Whole Payment Total

$$\text{DAMWAMTTOT} = \sum_{q} \text{DAMWAMTQSETOT}_{q}$$

RMR Day-Ahead Make-Whole Revenue Total

$$\text{RMRDAMWREVTOT} = \sum_{q} \text{DAMWRMRREVQSETOT}_{q}$$

Day-Ahead Energy Purchase Ratio Share per QSE

$$\text{DAERS}_{q} = \text{DAE}_{q} / \text{DAETOT}$$

$$\text{DAETOT} = \sum_{q} \text{DAE}_{q}$$

$$\text{DAE}_{q} = \sum_{p} \text{DAEP}_{q,p} + \sum_{j} \sum_{k} \text{RTOBL}_{q,(j,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
LADAMWAMT_{q}	$	*Day-Ahead Make-Whole Charge*—The allocated charge to QSE *q* to make whole all the eligible DAM-committed Resources for the hour.
DAMWAMTTOT	$	*Day-Ahead Make-Whole Payment Total*—The total of the Day-Ahead Make-Whole Payments to all QSEs for all DAM-committed non-RMR Resources for the hour.
DAMWAMTQSETOT_{q}	$	*Day-Ahead Make-Whole Payment QSE Total per QSE*—The total of the Day-Ahead Make-Whole Payments to QSE *q* for the DAM-committed non-RMR Generation Resources represented by this QSE for the hour.
RMRDAMWREVTOT	$	*RMR Day-Ahead Make-Whole Revenue Total*—The total of the RMR Day-Ahead Make-Whole Revenue for all DAM-committed RMR Units for the hour.
$\text{DAMWRMRREVQSETOT}_{q}$	$	*Day-Ahead Make-Whole RMR Revenue QSE Total per QSE*—The total of the Day-Ahead Make-Whole Revenue calculated for QSE *q* for DAM-committed RMR Units represented by this QSE for the hour.
DAERS_{q}	none	*Day-Ahead Energy Purchase Ratio Share per QSE*— The ratio of QSE *q*'s total amount of energy represented by its cleared DAM Energy Bids and PTP Obligation Bids, to the total amount of energy represented by all QSEs' cleared DAM Energy Bids and PTP Obligation Bids, for the hour.

Variable	Unit	Definition
DAETOT	MW	*Day-Ahead Energy Total*—The total amount of energy represented by all cleared DAM Energy Bids and all cleared PTP Obligation Bids for the hour.
DAE $_{q}$	MW	*Day-Ahead Energy per QSE*—QSE *q*'s total amount of energy, represented by its cleared DAM Energy Bids and PTP Obligation Bids, for the hour.
DAEP $_{q,\ p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s cleared DAM Energy Bids at the Settlement Point *p* for the hour.
RTOBL $_{q,\ (j,\ k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total amount of energy represented by QSE *q*'s cleared PTP Obligation Bids with the source *j* and the sink *k*, for the hour.
q	none	A QSE.
r	none	An RMR Unit.
p	none	A Settlement Point.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

4.6.3 Settlement for PTP Obligations Bought in DAM

(1) ERCOT shall pay or charge a QSE for a cleared PTP Obligation Bid the difference in the DAM Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The charge or payment to each QSE for a given Operating Hour of its cleared PTP Obligation Bids with each pair of source and sink Settlement Points is calculated as follows:

$$\mathbf{DARTOBLAMT}_{\boldsymbol{q,\ (j,\ k)}} \quad = \quad \mathbf{DAOBLPR}_{\boldsymbol{(j,\ k)}} \ ^{*} \ \mathbf{RTOBL}_{\boldsymbol{q,\ (j,\ k)}}$$

Where:

$$\text{DAOBLPR}_{(j,\ k)} = \quad \text{DASPP}_{k} - \text{DASPP}_{j}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARTOBLAMT $_{q,\ (j,\ k)}$	$	*Day-Ahead Real-Time Obligation Amount per QSE per pair of source and sink*—The charge or payment to QSE q for a PTP Obligation Bid cleared in the DAM with the source *j* and the sink *k*, for the hour.
DAOBLPR $_{(j,\ k)}$	$/MW per hour	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation Bid with the source *j* and the sink *k*, for the hour.
DASPP $_{j}$	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j* for the hour.
DASPP $_{k}$	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k* for the hour.

Variable	Unit	Definition
RTOBL $_{q, (j, k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation Bids cleared in the DAM for the source *j* and the sink *k* for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(2) The net total charge or payment to the QSE for the hour of all its cleared PTP Obligation Bids is calculated as follows:

$$\mathbf{DARTOBLAMTQSETOT}_{q} = \sum_{j} \sum_{k} \mathbf{DARTOBLAMT}_{q, (j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARTOBLAMTQSETOT$_q$	$	*Day-Ahead Real-Time Obligation Amount QSE Total per QSE* - The net total charge or payment to QSE q for all its PTP Obligation Bids cleared in the DAM for the hour.
DARTOBLAMT $_{q, (j, k)}$	$	*Day-Ahead Real-Time Obligation Amount per QSE per pair of source and sink* - The charge or payment to QSE q for a PTP Obligation Bids cleared in the DAM with the source *j* and the sink *k*, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

4.6.4 Settlement of Ancillary Services Procured in the DAM

ERCOT shall pay each QSE providing Ancillary Services procured in the DAM the amount of Ancillary Service Capacity in MW procured from the QSE multiplied by the MCPC for the Ancillary Service provided, expressed in $/MW. Each QSE shall pay for its share of each Ancillary Service procured by ERCOT on behalf of the QSE through the DAM.

4.6.4.1 Payments for Ancillary Services Procured in the DAM

4.6.4.1.1 Regulation Up Service Payment

ERCOT shall pay each QSE whose Ancillary Service Offers to provide Reg-Up to ERCOT were cleared in the DAM, for each hour as follows:

$$\mathbf{PCRUAMT}_{q} = (-1) * \mathbf{MCPCRU}_{DAM} * \mathbf{PCRU}_{q, DAM}$$

Where:

$$PCRU_{q,\ DAM} = \sum_{r} PCRUR_{r,\ q,\ DAM}$$

The above variables are defined as follows:

Variable	Unit	Definition
$PCRUAMT_{q}$	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q* for the hour.
$PCRU_{q, DAM}$	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$PCRUR_{r, q, DAM}$	MW	*Procured Capacity for Reg-Up from Resource per Resource per QSE in DAM*—The Reg-Up capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour.
$MCPCRU_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up in DAM*—The DAM MCPC for Reg-Up for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.1.2 Regulation Down Service Payment

ERCOT shall pay each QSE whose Ancillary Service Offers to provide Reg-Down to ERCOT were cleared in the DAM, for each hour as follows:

$$\mathbf{PCRDAMT}_{q} = \mathbf{(-1) * MCPCRD}_{DAM} \mathbf{* PCRD}_{q,\ DAM}$$

Where:

$$PCRD_{q,\ DAM} = \sum_{r} PCRDR_{r,\ q,\ DAM}$$

The above variables are defined as follows:

Variable	Unit	Definition
$PCRDAMT_{q}$	$	*Procured Capacity for Reg-Down Amount per QSE in DAM*—The DAM Reg-Down payment for QSE *q* for the hour.
$PCRD_{q, DAM}$	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$PCRDR_{r, q, DAM}$	MW	*Procured Capacity for Reg-Down from Resource per Resource per QSE in DAM*—The Reg-Down capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour.
$MCPCRD_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down in DAM*—The DAM MCPC for Reg-Down for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.1.3 Responsive Reserve Service Payment

ERCOT shall pay each QSE whose Ancillary Service Offers to provide Responsive Reserve to ERCOT were cleared in the DAM, for each hour as follows:

$$\mathbf{PCRRAMT}_{q} = \mathbf{(-1) * MCPCRR}_{DAM} \mathbf{* PCRR}_{q,\,DAM}$$

Where:

$$\text{PCRR}_{q,\,DAM} = \sum_{r} \text{PCRRR}_{r,\,q,\,DAM}$$

The above variables are defined as follows:

Variable	Unit	Definition
PCRRAMT_{q}	$	*Procured Capacity for Responsive Reserve Amount per QSE in DAM*—The DAM Responsive Reserve payment for QSE *q* for the hour.
$\text{PCRR}_{q,\,DAM}$	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total Responsive Reserve Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$\text{PCRRR}_{r,\,q,\,DAM}$	MW	*Procured Capacity for Responsive Reserve from Resource per Resource per QSE in DAM*—The Responsive Reserve capacity quantity awarded to QSE *q* in the DAM for Resource *r* for the hour.
MCPCRR_{DAM}	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for Responsive Reserve for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.1.4 Non-Spinning Reserve Service Payment

ERCOT shall pay each QSE whose Ancillary Service Offers to provide Non-Spin to ERCOT were cleared in the DAM, for each hour as follows:

$$\mathbf{PCNSAMT}_{q} = \mathbf{(-1) * MCPCNS}_{DAM} \mathbf{* PCNS}_{q,\,DAM}$$

Where:

$$\text{PCNS}_{q,\,DAM} = \sum_{r} \text{PCNSR}_{r,\,q,\,DAM}$$

The above variables are defined as follows:

Variable	Unit	Definition
PCNSAMT_{q}	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
$\text{PCNS}_{q,\,DAM}$	MW	*Procured Capacity for Non-Spin per QSE in DAM*—The total Non-Spin Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by this QSE for the hour.
$\text{PCNSR}_{r,\,q\,DAM}$	MW	*Procured Capacity for Non-Spin from Resource per Resource per QSE in DAM*—The Non-Spin capacity quantity awarded to QSE *q* in the DAM for

		Resource *r* for the hour.
$MCPCNS_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin in DAM*—The DAM MCPC for Non-Spin for the hour.
r	none	A Resource.
q	none	A QSE.

4.6.4.2 Charges for Ancillary Services Procurement in the DAM

4.6.4.2.1 Regulation Up Service Charge

Each QSE shall pay to ERCOT a Reg-Up Service charge for each hour as follows:

$$\mathbf{DARUAMT}_{q} = \mathbf{DARUPR * DARUQ}_{q}$$

Where:

$$DARUPR = (-1) * PCRUAMTTOT / DARUQTOT$$

$$PCRUAMTTOT = \sum_{q} PCRUAMT_{q}$$

$$DARUQTOT = \sum_{q} DARUQ_{q}$$

$$DARUQ_{q} = DARUO_{q} – DASARUQ_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DARUAMT_{q}$	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Up, for the hour.
DARUPR	$/MW per hour	*Day-Ahead Reg-Up Price*—The Day-Ahead Reg-Up price for the hour.
$DARUQ_{q}$	MW	*Day-Ahead Reg-Up Quantity per QSE*—The portion of QSE *q*'s Day-Ahead Ancillary Service obligation that is not self-arranged, for the hour.
PCRUAMTTOT	$	*Procured Capacity for Reg-Up Amount Total in DAM*—The total of the DAM Reg-Up payments for all QSEs for the hour.
$PCRUAMT_{q}$	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q* for the hour.
DARUQTOT	MW	*Day-Ahead Reg-Up Quantity Total*—The sum of every QSE's portion of its Day-Ahead Ancillary Service obligation that is not self-arranged, for the hour.
$DARUO_{q}$	MW	*Day-Ahead Reg-Up Obligation per QSE*—The Reg-Up capacity obligation for QSE *q* for the DAM for the hour.
$DASARUQ_{q}$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.4.2.2 *Regulation Down Service Charge*

Each QSE shall pay to ERCOT a Reg-Down Service charge for each hour as follows:

$$\mathbf{DARDAMT}_{q} = \mathbf{DARDPR * DARDQ}_{q}$$

Where:

$$\text{DARDPR} = (-1) * \text{PCRDAMTTOT} / \text{DARDQTOT}$$

$$\text{PCRDAMTTOT} = \sum_{q} \text{PCRDAMT}_{q}$$

$$\text{DARDQTOT} = \sum_{q} \text{DARDQ}_{q}$$

$$\text{DARDQ}_{q} = \text{DARDO}_{q} - \text{DASARDQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARDAMT_{q}	$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the hour.
DARDPR	$/MW per hour	*Day-Ahead Reg-Down Price*—The Day-Ahead Reg-Down price for the hour.
DARDQ_{q}	MW	*Day-Ahead Reg-Down Quantity per QSE*—The portion of QSE *q*'s Day-Ahead Ancillary Service obligation that is not self-arranged, for the hour.
PCRDAMTTOT	$	*Procured Capacity for Reg-Down Amount Total in DAM*—The total of the DAM Reg-Down payments for all QSEs for the hour.
PCRDAMT_{q}	$	*Procured Capacity for Reg-Down Amount per QSE in DAM*—The DAM Reg-Down payment for QSE *q* for the hour.
DARDQTOT	MW	*Day-Ahead Reg-Down Quantity Total*—The sum of every QSE's portion of its Day-Ahead Ancillary Service obligation that is not self-arranged, for the hour.
DARDO_{q}	MW	*Day-Ahead Reg-Down Obligation per QSE*—The Reg-Down capacity obligation for QSE *q* for the DAM for the hour.
DASARDQ_{q}	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The Self-Arranged Reg-Down Quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.4.2.3 *Responsive Reserve Service Charge*

Each QSE shall pay to ERCOT a Responsive Reserve Service (RRS) charge for each hour as follows:

$$\mathbf{DARRAMT}_{q} = \mathbf{DARRPR * DARRQ}_{q}$$

Where:

$$DARRPR = (-1) * PCRRAMTTOT / DARRQTOT$$

$$PCRRAMTTOT = \sum_{q} PCRRAMT_{q}$$

$$DARRQTOT = \sum_{q} DARRQ_{q}$$

$$DARRQ_{q} = DARRO_{q} – DASARRQ_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DARRAMT_{q}$	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*’s share of the DAM cost for Responsive Reserve, for the hour.
DARRPR	$/MW per hour	*Day-Ahead Responsive Reserve Price*—The Day-Ahead Responsive Reserve price for the hour.
$DARRQ_{q}$	MW	*Day-Ahead Responsive Reserve Quantity per QSE*—The portion of QSE *q*’s Day-Ahead Ancillary Service obligation that is not self-arranged, for the hour.
PCRRAMTTOT	$	*Procured Capacity for Responsive Reserve Amount Total in DAM*—The total of the DAM Responsive Reserve payments for all QSEs for the hour.
$PCRRAMT_{q}$	$	*Procured Capacity for Responsive Reserve Amount per QSE for DAM*—The DAM Responsive Reserve payment for QSE *q* for the hour.
DARRQTOT	MW	*Day-Ahead Responsive Reserve Quantity Total*—The sum of every QSE’s portion of its Day-Ahead Ancillary Service obligation that is not self-arranged, for the hour.
$DARRO_{q}$	MW	*Day-Ahead Responsive Reserve Obligation per QSE*—The Responsive Reserve capacity obligation for QSE *q* for the DAM for the hour.
$DASARRQ_{q}$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged Responsive Reserve quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.4.2.4 Non-Spinning Reserve Service Charge

Each QSE shall pay to ERCOT a Non-Spin Service charge for each hour as follows:

$$\mathbf{DANSAMT_{\mathit{q}} = DANSPR * DANSQ_{\mathit{q}}}$$

Where:

$$DANSPR = (-1) * PCNSAMTTOT / DANSQTOT$$

$$\text{PCNSAMTTOT} = \sum_{q} \text{PCNSAMT}_{q}$$

$$\text{DANSQTOT} = \sum_{q} \text{DANSQ}_{q}$$

$$\text{DANSQ}_{q} = \text{DANSO}_{q} - \text{DASANSQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
DANSAMT $_q$	$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin, for the hour.
DANSPR	$/MW per hour	*Day-Ahead Non-Spin Price*—The Day-Ahead Non-Spin price for the hour.
DANSQ $_q$	MW	*Day-Ahead Non-Spin Quantity per QSE*—The portion of QSE *q*'s Day-Ahead Ancillary Service obligation that is not self-arranged capacity, for the hour.
PCNSAMTTOT	$	*Procured Capacity for Non-Spin Amount Total in DAM*—The total of the DAM Non-Spin payments for all QSEs for the hour.
PCNSAMT $_q$	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
DANSQTOT	MW	*Day-Ahead Non-Spin Quantity Total*—The sum of every QSE's portion of its Day-Ahead Ancillary Service obligation that is not self-arranged, for the hour.
DANSO $_q$	MW	*Day-Ahead Non-Spin Obligation per QSE*—The Non-Spin capacity obligation for QSE *q* for the DAM for the hour.
DASANSQ $_q$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.6.5 Calculation of "Average Incremental Energy Cost" (AIEC)

The methodology of AIEC calculation is presented below. AIEC is used to account for the additional cost for a Generation Resource to produce energy above its LSL. This cost calculation methodology is used for the calculation of DAAIEC, RTAIEC, RTVSSAIEC, and RTHSLAIEC variables. The DAAIEC and RTAIEC are subject to the Energy Offer Curve Cap, while the RTVSSAIEC and RTHSLAIEC are not subject to price caps.

I. Energy Offer Curve

Index (i)	MW	$/MWh
1	Q_1	P_1
2	Q_2	P_2
⋮	⋮	⋮

N (N≤10)	Q_N	P_N

Variables DAAIEC and RTAIEC should calculate the associated price caps as specified in steps II through IV, the calculation process for Variables RTVSSAIEC and RTHSLAIEC should skip steps II through IV and continue with step V.

II. MW quantity corresponding with Energy Offer Curve Cap[1], $\overline{P}$ (\$/MWh), where $P_i < \overline{P} \le P_{i+1}$ ($i = 1, 2, \cdots, N-1$)

$$\overline{Q} \text{ (\$/MWh), where } \overline{Q} = Q_i + \frac{Q_{i+1} - Q_i}{P_{i+1} - P_i}(\overline{P} - P_i)$$

III. Energy Offer Curve capped with the Energy Offer Curve Cap;

A. When $\overline{P} < P_N$

Index (j)	MW	\$/MWh
1	Q_1	P_1
⋮	⋮	⋮
i	Q_i	P_i
i+1	$\overline{Q}$	$\overline{P}$
i+2	Q_N	$\overline{P}$

B. When $\overline{P} \ge P_N$:

Index (j)	MW	\$/MWh
1	Q_1	P_1
⋮	⋮	⋮
N	Q_N	P_N

IV. Cleared offer on the capped Energy Offer Curve

A. When $\overline{P} < P_N$:

$$\text{Q (MW), where } Q_j < Q \le Q_{j+1} \; (j = 1, \cdots, i, i+1)$$

[1] If the Energy Offer Curve Cap is less than the lowest price of the energy offer curve, the AIEC is the Energy Offer Curve Cap. If the Energy Offer Curve Cap is greater than the highest price of the energy offer curve, then $\overline{Q}$ does not need to be calculated.

B. When $\overline{P} \geq P_N$:

$$\text{Q (MW), where } Q_j < Q \leq Q_{j+1} \ (j = 1, \cdots, N-1)$$

V. Incremental energy price corresponding with cleared offer, on the capped Energy Offer Curve:

$$\text{P (\$/MWh), where } P = P_j + \frac{P_{j+1} - P_j}{Q_{j+1} - Q_j}(Q - Q_j)$$

VI. AIEC corresponding with ($Q-Q_1>0$), on the capped Energy Offer Curve:

$$AIEC = \begin{cases} \dfrac{P_1 + P}{2}, \ for\ Q_1 < Q \leq Q_2 \\ \left[\displaystyle\sum_{k=1}^{j-1} \frac{P_k + P_{k+1}}{2}(Q_{k+1} - Q_k) + \frac{P_j + P}{2}(Q - Q_j)\right] \Big/ (Q - Q_1), \ for\ Q > Q_2 \end{cases}$$

ERCOT Nodal Protocols

Section 5: Transmission Security Analysis and Reliability Unit Commitment

Updated: February 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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5 TRANSMISSION SECURITY ANALYSIS AND RELIABILITY UNIT COMMITMENT (RUC)

5.1 Introduction

(1) Transmission Security Analysis and Reliability Unit Commitment (RUC) are used to ensure Transmission System reliability and to ensure that enough Resource capacity, in addition to Ancillary Service capacity, is committed in the right locations to reliably serve the forecasted Load on the ERCOT System.

(2) ERCOT shall conduct at least one Day-Ahead RUC (DRUC) and at least one Hourly RUC (HRUC) before each hour of the Operating Day. ERCOT, in its sole discretion, may conduct a RUC at any time to evaluate and resolve reliability issues.

(3) The DRUC must be run after the close of the Day-Ahead Market (DAM).

(4) The DRUC uses Three-Part Supply Offers submitted before the DAM by QSEs that were considered in the DAM but not awarded in the DAM. A QSE may not submit a Three-Part Supply Offer to be considered in the DRUC unless the offer was also submitted for consideration in the DAM.

(5) ERCOT must initiate the HRUC process at least one hour before the Operating Hour to fine-tune the Resource commitments using updated Load forecasts and updated Outage information.

(6) The RUC Study Period for DRUC is the next Operating Day. The RUC Study Period for HRUC is the balance of the current Operating Day plus the next Operating Day if the DRUC for the Operating Day has been solved.

(7) HRUC may decommit Resources only to maintain the reliability of the ERCOT System.

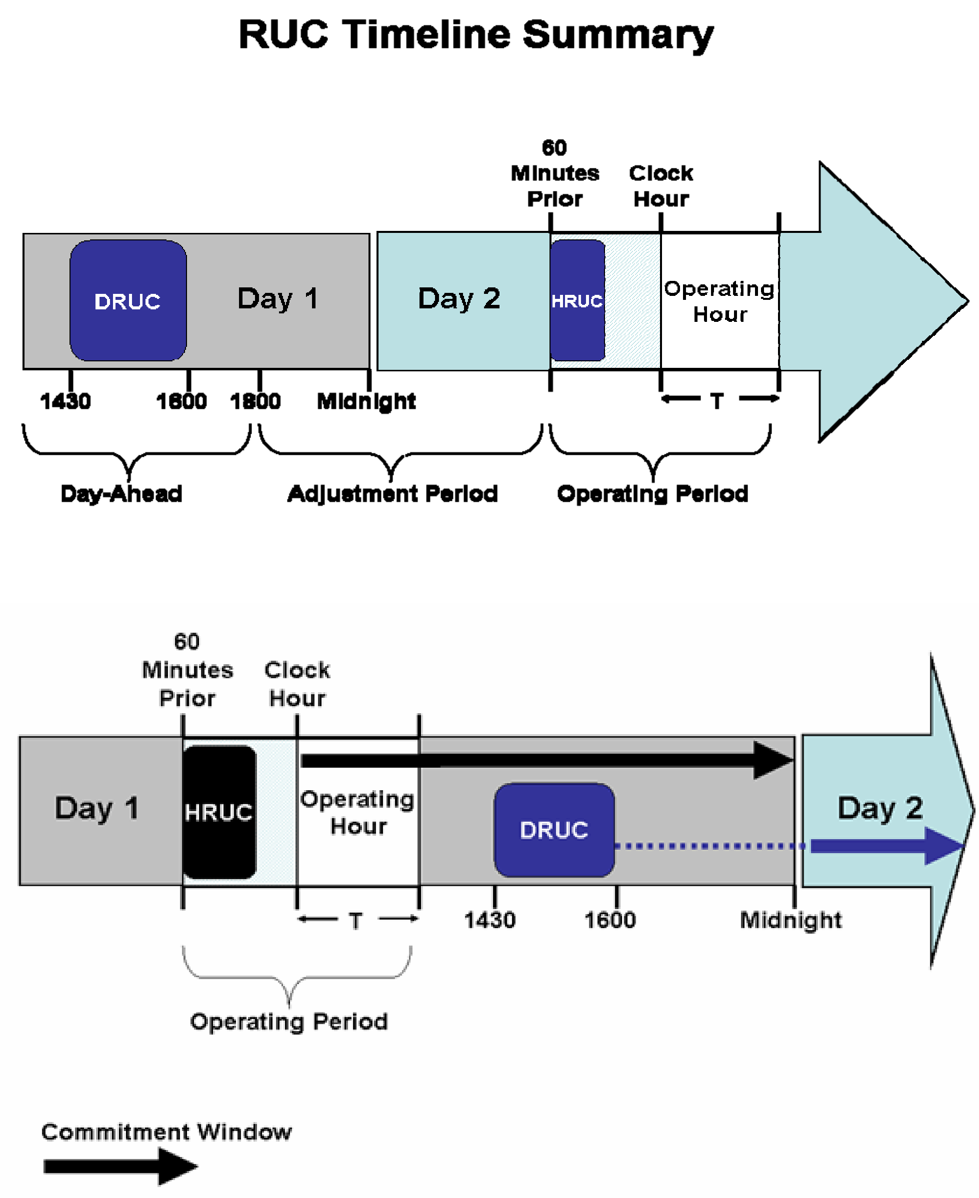
(8) For each RUC Study Period, the RUC considers capacity requirements for each hour of the RUC Study Period with the objective of minimizing costs based on Three-Part Supply Offers and while substituting a proxy Energy Offer Curve for the Energy Offer Curve. The proxy Energy Offer Curve is calculated in a way that minimizes the effect of the proxy Energy Offer Curves on optimization.

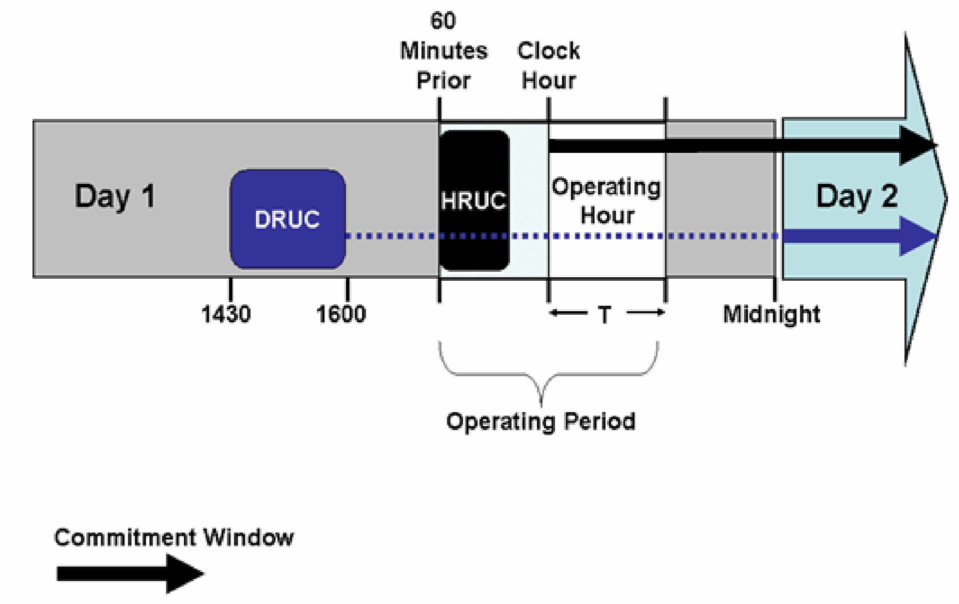
(9) The calculated Resource commitments arising from each RUC process must be reviewed by ERCOT before issuing Dispatch Instructions to QSEs to commit, extend, or decommit Resources.

(10) The Security Sequence is a set of prerequisite processes for RUC that describes the key system components and inputs that are required to support the RUC process, the RUC process itself, and the ERCOT review of the Resource commitment recommendations made by the RUC process.

(11) The RUC process may not be used to buy Ancillary Service unless the Ancillary Service Offers submitted in the DAM are insufficient to meet the requirements of the Ancillary Service Plan.

5.2 Reliability Unit Commitment Timeline Summary





5.3 ERCOT Security Sequence Responsibilities

(1) ERCOT shall start the Day-Ahead Reliability Unit Commitment (DRUC) process at 1430 in the Day Ahead.

(2) For each DRUC, ERCOT shall use a snapshot of Resource commitments taken at 1430 in the Day Ahead to settle RUC charges. For each HRUC, ERCOT shall use a snapshot of Resource commitments from each QSE's most recently submitted COP before HRUC execution to settle RUC charges.

(3) For each RUC process, ERCOT shall:

(a) Execute the Security Sequence described in Section 5.5, Security Sequence, Including RUC, including:

(i) Validating Three-Part Supply Offers, defined in Section 4.4.9.1, Three-Part Supply Offers; and

(ii) Reviewing the Resource commitment recommendations made by the RUC algorithm; and

(b) Post to the MIS Secure Area, the following information related to the RUC:

(i) All active and binding transmission constraints (contingency and overloaded element pair information where available) used as inputs to RUC; and

(ii) All Resources that were committed or decommitted by the RUC process; and

(c) Issue Dispatch Instructions to notify each QSE of its Resource commitments or decommittments.

(4) ERCOT shall provide each QSE with the information necessary to pre-validate their data for DRUC and HRUC including:

(a) Publishing validation rules for offers, bids, and trades; and

(b) Posting any software documentation and code that is not Protected Information to the MIS Secure Area within five Business Days of receipt by ERCOT.

5.4 QSE Security Sequence Responsibilities

During the Security Sequence, each QSE must:

(1) Submit its COP and update its COP as required in Section 3.9, Current Operating Plan (COP);

(2) Submit any Three-Part Supply Offers before:

(a) 1000 in the Day-Ahead for the DAM and DRUC being run in that Day-Ahead, if the QSE wants the offer to be used in those DAM and DRUC processes; and

(b) The end of the Adjustment Period for each HRUC, if the QSE wants the offer to be used in the HRUC process;

(3) Submit any Capacity Trades before 1430 in the Day-Ahead for the DRUC and before the end of the Adjustment Period for each HRUC, if the QSE wants those Capacity Trades included in the calculation of RUC settlement;

(4) Submit any Energy Trades before 1430 in the Day-Ahead for the DRUC and by the end of the Adjustment Period for each HRUC; if the QSE wants those Energy Trades included in the calculation of RUC Settlement; and

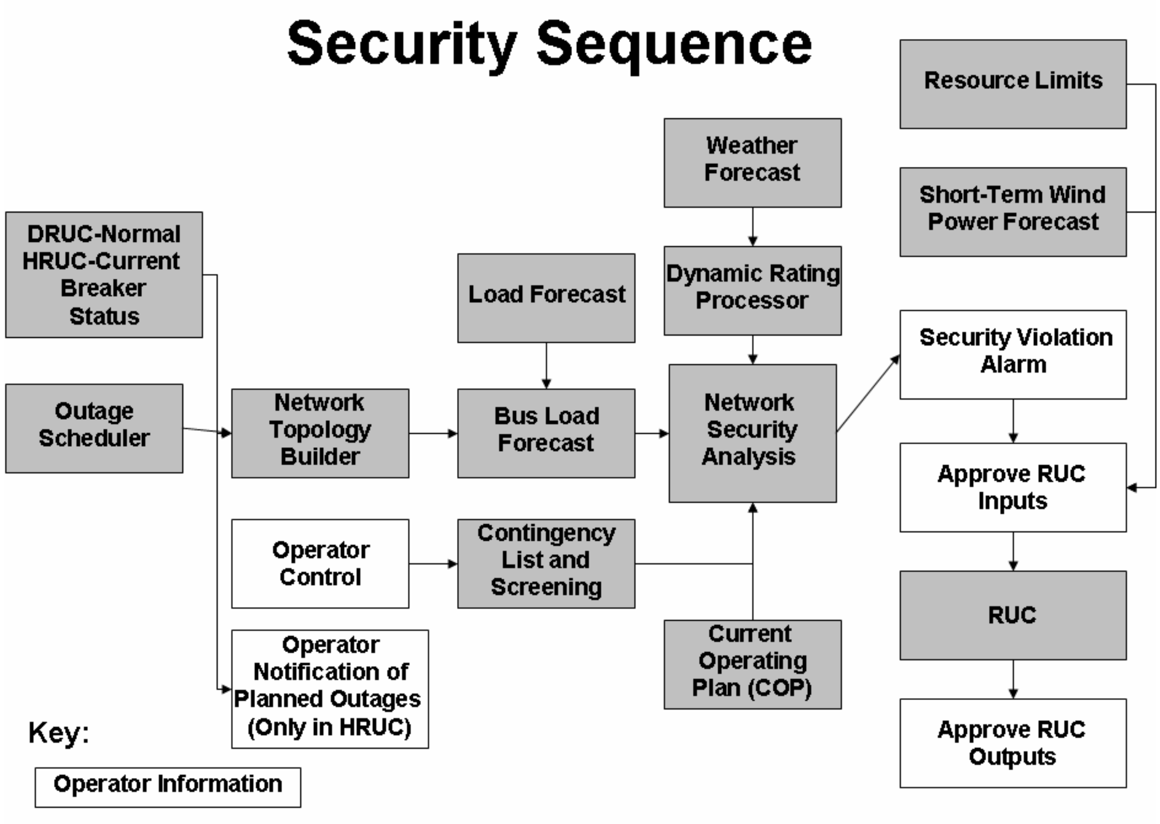
(5) Submit an updated COP before 1430 in the Day-Ahead that shows the specific Resources that will be used to supply the QSE's Ancillary Service Supply Responsibility; and

(6) Acknowledge receipt of Resource commitment or decommitment Dispatch Instructions by submitting an updated COP.

5.5 Security Sequence, Including RUC

5.5.1 Security Sequence

(1) The figure below highlights the key computational modules and processes that are used in the Security Sequence:



(2) The Security Sequence uses a subset of the computational modules used by the Real-Time Sequence. A more detailed explanation of those computational modules can be found in Section 6.5.7.1, Real-Time Sequence. The main distinction between the two models concerns inputs. The inputs into the Security Sequence are based on a snapshot of projected hourly system conditions and constraints.

(3) The Security Sequence uses the status of all transmission breakers and switches(current status for HRUC and normal status for DRUC), updated for approved Planned Outages for equipment out of service and returned to service for building a representation of the ERCOT Transmission Grid for each hour of the RUC Study Period. The Network Topology Processor constructs a network model for each hour that must be used by the Bus Load Forecast to estimate the hourly load for each transmission bus.

(4) The weather forecast obtained by ERCOT must be provided to the Dynamic Rating Processor to create weather-adjusted MVA limits for each hour of the RUC Study Period for all transmission lines and transformers that have Dynamic Ratings.

(5) ERCOT shall analyze base configuration, select n-1 contingencies and select n-2 contingencies under the Operating Guides. The Operating Guides must also specify the criteria by which ERCOT may remove contingencies from the list. ERCOT shall post to the MIS Secure Area the standard contingency list, including identification of changes from previous versions before being used in the Security Sequence. ERCOT shall

evaluate the need for Resource-specific deployments during Real-Time operations for management of congestion consistent with the Operating Guides.

(6) ERCOT shall also post to the MIS Secure Area any contingencies temporarily removed from the standard contingency list by ERCOT immediately after successful execution of the Security Sequence. ERCOT shall include the reason for removal of any contingency as soon as practicable but not later than one hour after removal.

(7) As part of the Network Security Analysis, for each hour of the RUC Study Period, ERCOT shall analyze all selected contingencies and perform the following:

(a) Perform full AC analysis of all contingencies;

(b) Monitor element and bus voltage limit violations; and

(c) Monitor transmission line and transformer security violations.

(8) As part of the Network Security Analysis, if there is an approved Remedial Action Plan (RAP) available, it must be used before considering a Resource commitment.

(9) ERCOT shall review all security violations prior to RUC execution.

(10) ERCOT shall model all approved Special Protection Systems (SPSs) and RAPs in the contingency analysis. The computational modules must enable ERCOT to analyze contingencies, including the effects of all approved automatically deployed SPSs.

(11) ERCOT may deselect certain contingencies known to cause errors or that otherwise result in inconclusive study output in the RUC. On continued de-selection of contingencies, ERCOT shall prepare an analysis to determine the cause of the error. ERCOT may use information from the DAM processes as decision support during the Hour-Ahead processes. ERCOT shall post to the MIS Secure Area any contingencies deselected by ERCOT and must include the reason for removal as soon as practicable, but not later than one hour after deselection.

5.5.2 Reliability Unit Commitment (RUC) Process

(1) The RUC process recommends commitment of Generation Resources, to match ERCOT's forecasted Load, subject to all transmission constraints and Resource performance characteristics. The RUC process takes into account Resources already committed in the DAM, Resources already self-committed in the COPs, Resources already committed in previous RUCs, and Resource capacity already committed to provide Ancillary Service. The formulation of the RUC objective function must employ penalty factors on violations of security constraints. The objective of the RUC process is to minimize costs based on Three-Part Supply Offers, substituting a proxy Energy Offer Curve for the Energy Offer Curve, over the RUC study period.

(2) The RUC process can recommend Resource decommitment. ERCOT may only decommit a Resource to resolve transmission constraints that are otherwise unresolvable. QFs may be decommitted only after all other types of Resources have been assessed for decommitment. In addition, the HRUC process provides decision support to ERCOT regarding a Resource decommitment requested by a QSE.

(3) ERCOT shall review the RUC-recommended Resource commitments to assess feasibility and shall make any changes that it considers necessary, in its sole discretion. ERCOT shall notify each QSE which of its Resources have been committed as a result of the RUC process. ERCOT shall, within one day after making any changes to the RUC-recommended commitments, post to the MIS Secure Area any changes that ERCOT made to the RUC-recommended commitments with an explanation of the changes.

(4) To determine the projected energy output level of each Resource and to project potential congestion patterns for each hour of the RUC, ERCOT shall calculate proxy Energy Offer Curves based on the Mitigated Offer Caps for the type of Resource as specified in Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, for use in the RUC. Proxy Energy Offer Curves are calculated by multiplying the Mitigated Offer Cap by a constant selected by ERCOT from time to time that is no more than 0.10% and applying the cost for all Generation Resource output between HSL and LSL.

(5) ERCOT shall use the RUC process to evaluate the need to commit Resources for which a QSE has submitted Three-Part Supply Offers and other available Off-Line Resources in addition to Resources that are planned to be On-Line during the RUC Study Period. All of the above commitment information must be as specified in the QSE's COP.

(6) ERCOT shall create Three-Part Supply Offers for all Resources that did not submit a Three-Part Supply Offer but are specified as available but Off-Line, excluding Resources with a Resource Status of EMR, in a QSE's COP. For such Resources, ERCOT shall use in the RUC process 150% of any approved verifiable startup cost and verifiable minimum-energy cost or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and the applicable Resource Category Generic Minimum-Energy Offer Cost as described specified in Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, registered with ERCOT. However for settlement purposes, ERCOT shall use any approved verifiable startup costs and verifiable minimum-energy cost for such Resources, or if verifiable costs have not been approved, the applicable Resource Category Generic Startup Offer Cost and Generic Minimum-Energy Offer Cost.

(7) The RUC process must treat all Resource capacity providing Ancillary Service as unavailable for the RUC Study Period, unless that treatment leads to infeasibility (*i.e.*, that capacity is needed to resolve some local transmission problem that cannot be resolved by any other means). In such cases, ERCOT shall inform each affected QSE of the amount of its Resource capacity that does not qualify to provide Ancillary Service, and the projected hours for which this is the case. In that event, the affected QSE may, under Section 6.4.8.1.2, Replacement of Undeliverable Ancillary Service Due to Transmission Constraints, either:

(a) Substitute capacity from Resources represented by that QSE;

(b) Substitute capacity from other QSEs using Ancillary Service Trades; or

(c) Ask ERCOT to replace the capacity.

(8) Factors included in the RUC process are:

(a) ERCOT System-wide hourly Load forecast allocated appropriately over Load buses;

(b) Transmission constraints – Transfer limits on energy flows through the electricity network;

(i) Thermal constraints – protect transmission facilities against thermal overload;

(ii) Generic constraints – protect the transmission system against transient instability, dynamic instability or voltage collapse;

(c) Planned transmission topology;

(d) Energy sufficiency constraints;

(e) Inputs from the COP, as appropriate;

(f) Inputs from Resource Parameters, as appropriate;

(g) Each Generation Resource's Minimum-Energy Offer and Startup Offer, from its Three-Part Supply Offer;

(h) Any Generation Resource that is Off-Line and available but does not have a Three-Part Supply Offer;

(i) Forced Outage information; and

(j) Inputs from the eight-day look ahead planning tool, which may potentially keep a unit online (or start a unit for the next day) so that a unit minimum duration between starts does not limit the availability of the unit (for security reasons).

(9) The Hourly RUC process (HRUC) and the Day-Ahead RUC process (DRUC) are as follows:

(a) The HRUC process uses current Resource Status for the initial condition for the first hour of the RUC Study Period. All HRUC processes use the projected status of transmission breakers and switches starting with current status and updated for each remaining hour in the study as indicated in the COP for Resources and in the Outage Scheduler for transmission elements.

(b) The DRUC process uses the Day-Ahead forecast of total ERCOT Load for each hour of the Operating Day. The HRUC process uses the current hourly forecast of total ERCOT Load for each hour in the RUC Study Period.

(c) The DRUC process uses the Day-Ahead weather forecast for each hour of the Operating Day. The HRUC process uses the weather forecast information for each hour of the balance of the RUC Study Period.

(10) The QSE may not use a Resource to meet its Ancillary Service Supply Responsibility during that Resource's RUC-Committed Interval.

5.5.3 Communication of RUC Commitments and Decommitments

(1) The output of the RUC process is the cleared Resource commitments and decommitments.

(2) ERCOT shall notify each QSE in the Day-Ahead of the DRUC Resource commitments and advisory decommitments that have been cleared by the RUC for the Resources that QSE represents. ERCOT shall notify each QSE of the HRUC Resource commitments and decommitments that have been cleared by the RUC for the Resources that QSE represents. Resource commitments must include the start interval and duration for which the Resource is required to be at least at LSL. Resource decommitments must include the interval in which the Resource is required to be Off-Line, duration, and reason for the decommitment.

(3) If ERCOT communicates HRUC commitments and decommitments verbally to a QSE, then the same Resource attributes communicated programmatically must be communicated when ERCOT gives a verbal Resource commitment or decommitment.

(4) The QSE shall acknowledge the notice or commitment or decommittment by changing the Resource Status of the affected Resources in the COP for RUC-Committed Intervals.

(5) At any time during the Adjustment Period, ERCOT shall notify the QSE representing an RMR Unit or a Synchronous Condenser Unit of any modification to the Delivery Plan for the RMR Unit or the Synchronous Condenser Unit made as a result of an HRUC process.

5.6 RUC Cost Eligibility

5.6.1 Verifiable Costs

(1) Make-Whole Payments for a Resource are based on the Startup Offers and Minimum-Energy Offers for the Resource, limited by caps. Until ERCOT approves verifiable unit-specific costs for that Resource, the caps are the Resource Category Startup Generic Cap and the Resource Category Minimum-Energy Generic Cap. When ERCOT approves verifiable unit-specific costs for that Resource the caps are those verifiable unit-specific

costs. A QSE may file verifiable unit-specific costs for a Resource at any time, but it must file those costs no later than 30 days after the first time that it receives a RUC instruction for that Resource. The most recent ERCOT-approved verifiable costs must be used going forward.

(2) These unit-specific verifiable costs may include and are limited to the following average incremental costs:

(a) Allocation of maintenance requirements based on number of starts between maintenance events using, at the option of the QSE, either:

(i) manufacturer-recommended maintenance schedule;

(ii) historical data for the unit and actual maintenance practices; or

(iii) another method approved in advance by ERCOT in writing;

(b) Startup fuel calculations based on recorded actual measured flows when the data is available or based on averages of historical flows for similar starts (for example, hot, cold, intermediate) when actual data is not available;

(c) Operation costs;

(d) Chemical costs;

(e) Water costs;

(f) Emission credits;

(g) Nodal implementation surcharges.

(3) These unit-specific verifiable costs may not include:

(a) Fixed costs, which are any cost that is incurred regardless of whether the unit is deployed or not; and

(b) Costs for which the QSE cannot provide sufficient documentation for ERCOT to verify the costs.

(4) The process for determining the verifiable actual costs must be developed by ERCOT, approved by the appropriate TAC subcommittee, and posted to the MIS Secure Area within one Business Day after initial approval and after each approved change.

(5) ERCOT shall notify a QSE to update verifiable cost data of a Resource when the Resource has received more than 50 RUC instructions meeting the criteria in Section 5.6.2, RUC Startup Cost Eligibility, in a year, but ERCOT may not request an update more frequently than annually.

(6) ERCOT shall notify a QSE to update verifiable cost data of a Resource if at least five years have passed since ERCOT previously approved verifiable cost data for that Resource if the Resource that has received at least one RUC instruction in the past.

(7) Within 30 days after receiving an update notice from ERCOT under item (5) or item (6) above, a QSE must submit verifiable cost data for the Resource. Despite the provisions in (1) above, if the QSE does not submit verifiable cost data within 30 days after receiving an update notice, then, until updated verifiable costs are approved, ERCOT shall determine payment using the lower of:

(a) Resource Category Startup Generic and Resource Category Minimum-Energy Generic Caps; and

(b) Current ERCOT-approved verifiable startup and minimum-energy costs.

5.6.1.1 Verifiable Startup Costs

The unit-specific verifiable costs for starting a Resource for each cold, intermediate, and hot start condition, as determined using the data submitted under Section 5.6.1, Verifiable Costs, above and the Resource Parameters for the Resource are:

(a) Actual fuel consumption rate per start (MMBtu/start) multiplied by a resource category generic fuel price (FIP, FOP, or $1.50 per MMBtu, as applicable); and

(b) Unit-specific verifiable operation and maintenance expenses.

5.6.1.2 Verifiable Minimum-Energy Costs

(1) The unit-specific verifiable minimum-energy costs for a Resource are:

(a) Actual fuel cost to operate the unit at LSL; plus

(b) Variable operation and maintenance expenses; plus

(c) Nodal implementation surcharges to operate the unit at LSL.

(2) The QSE must submit the Resource's cost information by season if the Resource's costs vary by season. For gas-fired units, the actual fuel costs must be calculated using the actual seasonal heat rate (which must be supplied to ERCOT with seasonal heat-rate test data) multiplied by FIP. For coal- and lignite-fired units, the actual fuel costs must be calculated using the actual seasonal heat rate multiplied by a deemed fuel price of $1.50 per MMBtu. For fuel oil-fired operations, the number of gallons burned must be multiplied by the FOP.

5.6.2 *RUC Startup Cost Eligibility*

(1) For purposes of this Section 5.6.2, all contiguous RUC-Committed Hours are considered as one RUC instruction. For each Resource, only one Startup Cost is eligible per block of contiguous RUC-Committed Hours.

(2) For a Resource's Startup Costs in the Operating Day, per RUC instruction, to be included in the calculation of the RUC Guarantee for that Operating Day, all the criteria below must be met:

(a) When the RUC instruction is given, the Resource must not be QSE-committed in the Settlement Interval immediately before the designated start hour or after the last hour of the RUC instruction;

(b) A later RUC instruction or QSE commitment must not connect the designated start hour or last hour of the RUC instruction to a block of QSE-Committed Intervals that was QSE-committed before the RUC instruction was given;

(c) The generation breakers must have been open, as indicated by a telemetered Resource status of Off-Line, for at least five minutes during the six hours preceding the first RUC-Committed Hour; and

(d) The generation breakers must have been closed, as indicated by a telemetered Resource status of On-Line, for at least one minute during the RUC commitment period or after the determined five-minute open breaker, as indicated by a telemetered Resource status of Off-Line, in the six hours preceding the first RUC-Committed Hour.

5.6.3 *Forced Outage of a RUC-Committed Resource*

(1) The calculation of a Make-Whole Payment for a RUC-committed Resource that is eligible to receive startup costs under Section 5.6.2, RUC Startup Cost Eligibility, and that experiences a Forced Outage after unit synchronization is governed by Section 5.6.2.

(2) If a RUC-committed Resource, which Resource is eligible to include startup costs in its RUC Guarantee under Section 5.6.2 without considering the criteria in item (2)(d) of Section 5.6.2, that experiences startup failure that creates a Forced Outage before breaker close, ERCOT shall include the Resource's submitted and approved verifiable actual costs in the Resource's RUC Guarantee, limited to the lesser of:

(a) costs that qualify as normal startup expenses, including fuel and operation and maintenance expenses, incurred before the event that caused the Forced Outage; or

(b) Resource's Startup Offer in the RUC.

(3) The process for determining the verifiable actual costs for a startup attempt under (2) above must be developed by ERCOT, approved by the appropriate TAC subcommittee, and posted to the MIS Secure Area within one Business Day after initial approval and after each approved change.

(4) The verifiable actual costs for a startup attempt under (2) shall only be included in the Resource's RUC Guarantee upon QSE notification of the startup attempt under (2) and approval of the verifiable actual costs under (3).

5.7 Settlement for RUC Process

5.7.1 RUC Make-Whole Payment

(1) To make up the difference when the revenues that a RUC-committed Resource receives are less than its costs as described in (2) below, ERCOT shall calculate a RUC Make-Whole Payment for that Operating Day for that Resource (whether committed by DRUC or HRUC).

(2) ERCOT shall pay to the QSE for the Resource a Make-Whole Payment if the RUC Guarantee calculated in Section 5.7.1.1, RUC Guarantee, is greater than the sum of:

(a) RUC Minimum-Energy revenue calculated in Section 5.7.1.2, RUC Minimum-Energy Revenue;

(b) Revenue less cost above LSL during RUC-Committed Hours calculated in Section 5.7.1.3, Revenue Less Cost Above LSL During RUC-Committed Hours; and

(c) Revenue less cost during QSE-Clawback Intervals calculated in Section 5.7.1.4, Revenue Less Cost During QSE Clawback Intervals.

(3) The RUC Make-Whole Payment to the QSE for each RUC-committed Resource, including RMR units, for each RUC-Committed Hour in an Operating Day is calculated as follows:

$$\text{RUCMWAMT}_{q,r,h} = (-1) * \text{Max}\,(0, \text{RUCG}_{q,r,d} - \text{RUCMEREV}_{q,r,d} - \text{RUCEXRR}_{q,r,d} - \text{RUCEXRQC}_{q,r,d}) / \text{RUCHR}_{q,r,d}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RUCMWAMT}_{q,r,h}$	$	*RUC Make-Whole Payment*—The RUC Make-Whole Payment to the QSE for a Resource, for each RUC-Committed Hour of the Operating Day.
$\text{RUCG}_{q,r,d}$	$	*RUC Guarantee*—The sum of the Resource's eligible Startup Costs and Minimum-Energy Costs during all RUC-Committed Hours, for the Operating

Variable	Unit	Definition
		Day. See Section 5.7.1.1, RUC Guarantee.
$RUCMEREV_{q,r,d}$	$	*RUC Minimum-Energy Revenue*—The sum of the energy revenues for the Resource's generation up to LSL during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.2, RUC Minimum-Energy Revenue.
$RUCEXRR_{q,r,d}$	$	*Revenue Less Cost Above LSL During RUC-Committed Hours*—The sum of the total revenue for the Resource's operating above its LSL less the cost during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.3, Revenue Less Cost Above LSL During RUC-Committed Hours.
$RUCEXRQC_{q,r,d}$	$	*Revenue Less Cost During QSE-Clawback Intervals*—The sum of the total revenue for the Resource less the cost during all QSE-Clawback Intervals, for the Operating Day. See Section 5.7.1.4, Revenue Less Cost During QSE Clawback Intervals.
$RUCHR_{q,r,d}$	None	RUC Hour – The total number of RUC-Committed Hours, for the Resource for the Operating Day.
q	None	A QSE.
r	None	A RUC-committed Generation Resource.
d	None	An Operating Day containing the RUC-commitment.
h	None	An hour in the RUC-commitment period.

5.7.1.1 RUC Guarantee

(1) If a validated Three-Part Supply Offer has been submitted for a Resource for the RUC, then the RUC Guarantee for that Resource is based on the Startup Offer and Minimum-Energy Offer in that validated Three-Part Supply Offer. If a validated Three-Part Supply Offer has not been submitted for a Resource for the RUC and ERCOT has not yet approved verifiable unit-specific costs for the Resource, then the RUC Guarantee for a Resource is based on the Resource Category Startup Generic Cap and the Resource Category Minimum-Energy Generic Cap. If a validated Three-Part Supply Offer has not been submitted for a Resource for the RUC and ERCOT has approved verifiable unit-specific costs for the Resource, then the RUC Guarantee for a Resource is based on the most recent ERCOT-approved verifiable unit-specific costs for that Resource. The RUC Guarantee Minimum-Energy Costs are prorated according to the actual generation when the Resource's average output during a 15-minute Settlement Interval is below the corresponding LSL.

(2) The RUC Guarantee is calculated as follows:

$$RUCG_{q,r,d} = \sum_{s} (SUPR_{q,r,s} * RUCSUFLAG_{q,r,s}) + \sum_{i} (MEPR_{q,r,i} * \text{Min}\ ((LSL_{q,r,i} * (1/4)),\ RTMG_{q,r,i}))$$

If the QSE submitted a validated Three-Part Supply Offer,

Then, $SUPR_{q,r,s} = SUO_{q,r,s}$

	$MEPR_{q,r,i}$	=	$MEO_{q,r,i}$
Otherwise,	$SUPR_{q,r,s}$	=	$SUCAP_{q,r,s}$
	$MEPR_{q,r,i}$	=	$MECAP_{q,r,i}$

If ERCOT has approved verifiable startup and minimum-energy costs for the Resource,

Then,	$SUCAP_{q,r,s}$	=	verifiable startup $costs_{q,r,s}$
	$MECAP_{q,r,i}$	=	verifiable minimum-energy $costs_{q,r,i}$
Otherwise,	$SUCAP_{q,r,s}$	=	$RCGSC_s$
	$MECAP_{q,r,i}$	=	$RCGMEC_i$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$RUCG_{q,r,d}$	$	*RUC Guarantee*—The sum of the Resource's eligible Startup Costs and Minimum-Energy Costs during all RUC-Committed Hours, for the Operating Day.
$SUPR_{q,r,s}$	$/Start	*Startup Price per start*—The settlement price for the start *s*.
$SUO_{q,r,s}$	$/Start	*Startup Offer per start*—Represents an offer for all costs incurred by a Generation Resource in starting up and reaching breaker close, as indicated by a telemetered Resource status of On-Line.
$SUCAP_{q,r,s}$	$/Start	*Startup Cap*—The amount used as startup costs if the QSE did not submit a validated Three-Part Supply Offer. The cap is the RCGSC unless ERCOT has approved verifiable unit-specific startup costs for that Resource, in which case the startup cap is the verifiable unit-specific startup cost. See Section 5.6.1, Verifiable Costs for more information on verifiable costs.
$RCGSC_s$	$/Start	*Resource Category Generic Startup Cost*—The Resource Category Generic Startup Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$RUCSUFLAG_{q,r,s}$	none	*RUC Startup Flag*—The flag that indicates whether or not the start *s* is eligible for RUC Make-Whole Payment. Its value is one if eligible; otherwise, zero. See Section 5.6.2, RUC Startup Cost Eligibility and Section 5.6.3, Forced Outage of RUC-Committed Resource, for more information on startup eligibility.
$MEPR_{q,r,i}$	$/MWh	*Minimum-Energy Price*—The settlement price for minimum energy for the Settlement Interval *i*.
$MEO_{q,r,i}$	$/MWh	*Minimum-Energy Offer*—Represents an offer for the costs incurred by a Resource in producing energy at the Resource's LSL for the Settlement Interval *i*.
$MECAP_{q,r,i}$	$/MWh	*Minimum Energy Cap*— The amount used for minimum-energy costs if the QSE did not submit a validated Three-Part Supply Offer. The cap is the RCGMEC unless ERCOT has approved verifiable unit-specific minimum energy costs for that Resource, in which case the Minimum-Energy cap is the verifiable unit-specific minimum energy cost. See Section 5.6.1, Verifiable

Variable	Unit	Definition
		Costs for more information on verifiable costs.
$RCGMEC_i$	\$/MWh	*Resource Category Generic Minimum-Energy Cost*—The Resource Category Generic Minimum Energy Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$RTMG_{q,r,i}$	MWh	*Real-Time Metered Generation*—The Resource's metered generation for the Settlement Interval *i*.
$LSL_{q,r,i}$	MW	*Low Sustained Limit*— The low sustainable limit of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
i	none	A 15-minute Settlement Interval within the hour that includes a RUC-commitment.
s	none	A start that is eligible to have its costs included in the RUC Guarantee.

5.7.1.2 RUC Minimum-Energy Revenue

The energy revenue for the Resource's generation up to LSL during all RUC-Committed Hours of the Operating Day is calculated as follows:

$$RUCMEREV_{q,r,d} = \sum_{i} (RTSPP_{p,i} * \text{Min}\,(RTMG_{q,r,i}, (LSL_{q,r,i} * (¼))))$$

The above variables are defined as follows:

Variable	Unit	Definition
$RUCMEREV_{q,r,d}$	\$	*RUC Minimum-Energy Revenue*—The sum of the energy revenues for the Resource's generation up to LSL during all RUC-Committed Hours, for the Operating Day.
$RTSPP_{p,i}$	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource Node for the Settlement Interval *i*.
$RTMG_{q,r,i}$	MWh	*Real-Time Metered Generation*—The Resource's metered generation for the Settlement Interval *i*.
$LSL_{q,r,i}$	MW	*Low Sustained Limit*— The low sustainable limit of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval within the hour that includes a RUC-commitment.

5.7.1.3 Revenue Less Cost Above LSL During RUC-Committed Hours

The total revenue for the Resource operating above its LSL less the cost based on the Resource's Energy Offer Curve capped by the energy offer curve cap (as described in Section 4.4.9.3, Energy Offer Curve and in Section 4.4.9.3.3, Energy Offer Curve Caps for Make-Whole Calculation Purposes) or proxy Energy Offer Curve described in Section 6.5.7.3, Security Constrained Economic Dispatch, as applicable, during all RUC-Committed Hours of the Operating Day is calculated as follows:

$$\begin{aligned} RUCEXRR_{q,r,d} = \text{Max}\ \{0, \sum_{i} [&RTSPP_{p,i} * \text{Max}\ (0, RTMG_{q,r,i} - (LSL_{q,r,i} * (¼))) \\ &+ (-1) * (VSSVARAMT_{q,r,i} + VSSEAMT_{q,r,i}) \\ &+ (-1) * EMREAMT_{q,r,i} \\ &- RTAIEC_{q,r,i} * \text{Max}\ (0, RTMG_{q,r,i} - (LSL_{q,r,i} * (¼)))]\} \end{aligned}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RUCEXRR_{q,r,d}$	$	*Revenue Less Cost Above LSL During RUC-Committed Hours*—The sum of the total revenue for the Resource operating above its LSL less the cost during all RUC-Committed Hours, for the Operating Day.
$RTSPP_{p,i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource's Settlement Point for the Settlement Interval *i*.
$RTAIEC_{q,r,i}$	$/MWh	*Real-Time Average Incremental Energy Cost*—The average incremental energy cost, calculated using the Energy Offer Curve capped by the Energy Offer Curve Cap, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.6.5, Calculation of "Average Incremental Energy Cost" (AIEC).
$RTMG_{q,r,i}$	MWh	*Real-Time Metered Generation*—The Resource's metered generation for the Settlement Interval *i*.
$LSL_{q,r,i}$	MW	*Low Sustained Limit*— The low sustainable limit of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP.
$VSSVARAMT_{q,r,i}$	$	*Voltage Support Service var Amount by interval*—The payment to the QSE for the VSS provided by Generation Resource for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments.
$VSSEAMT_{q,r,i}$	$	*Voltage Support Service Energy Amount by interval*—The lost opportunity payment to the QSE for ERCOT-directed VSS from the Generation Resource for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments.
$EMREAMT_{q,r,i}$	$	*Emergency Energy Amount by interval*—The payment to the QSE as additional compensation for the additional energy produced by the Generation Resource in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval

Variable	Unit	Definition
		i. See Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval within the hour that includes a RUC instruction.

5.7.1.4 Revenue Less Cost During QSE Clawback Intervals

The total revenue for the Resource less the cost based on the Resource's Energy Offer Curve capped by the energy offer curve cap (as described in Section 4.4.9.3, Energy Offer Curve and in Section 4.4.9.3.3, Energy Offer Curve Caps for Make-Whole Calculation Purposes) or proxy Energy Offer Curve described in Section 6.5.7.3, Security Constrained Economic Dispatch, as applicable, during all QSE Clawback Intervals of the Operating Day is calculated as follows:

$$
\begin{aligned}
\text{RUCEXRQC}_{q,r,d} = \quad & \text{Max}\ \Big\{0,\ \sum_{i} [(\text{RTSPP}_{p,i} * \text{RTMG}_{q,r,i})\\
& + (-1) * (\text{VSSVARAMT}_{q,r,i} + \text{VSSEAMT}_{q,r,i})\\
& + (-1) * \text{EMREAMT}_{q,r,i}\\
& - [\text{MEPR}_{q,r,i} * \text{Min}\ (\text{RTMG}_{q,r,i}, (\text{LSL}_{q,r,i} * (¼)))]\\
& - [\text{RTAIEC}_{q,r,i} * \text{Max}\ (0, \text{RTMG}_{q,r,i} - (\text{LSL}_{q,r,i} * (¼)))]]\Big\}
\end{aligned}
$$

If the QSE submitted a validated Three-Part Supply Offer,

Then, $\text{MEPR}_{q,r,i} = \text{MEO}_{q,r,i}$

Otherwise, $\text{MEPR}_{q,r,i} = \text{MECAP}_{q,r,i}$

If QSE verifiable minimum-energy costs for the Resource are on file,

Then, $\text{MECAP}_{q,r,i} = \text{verifiable minimum-energy costs}_{q,r,i}$

Otherwise, $\text{MECAP}_{q,r,i} = \text{RCGMEC}_{i}$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RUCEXRQC}_{q,r,d}$	$	*Revenue Less Cost During QSE-Clawback Intervals*—The sum of the total revenue for the Resource less the cost during all QSE-Clawback Intervals for the Operating Day.
$\text{RTSPP}_{p,i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource's Settlement Point for the Settlement Interval *i*.

Variable	Unit	Definition
$MEPR_{q,r,i}$	$/MWh	*Minimum-Energy Price*—The settlement price for minimum energy for the Settlement Interval *i*.
$MEO_{q,r,i}$	$/MWh	*Minimum-Energy Offer*—Represents an offer for the costs incurred by a Resource in producing energy at the Resource's LSL for the Settlement Interval *i*.
$MECAP_{q,r,i}$	$/MWh	*Minimum Energy Cap*— The amount used for minimum-energy costs if the QSE did not submit a validated Three-Part Supply Offer. The cap is the RCGMEC unless ERCOT has approved verifiable unit-specific minimum energy costs for that Resource, in which case the Minimum-Energy cap is the verifiable unit-specific minimum energy cost. See Section 5.6.1, Verifiable Costs for more information on verifiable costs.
$RCGMEC_i$	$/MWh	*Resource Category Generic Minimum-Energy Cost*—The Resource Category Generic Minimum-Energy Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$RTAIEC_{q,r,i}$	$/MWh	*Real-Time Average Incremental Energy Cost*—The average incremental energy cost, calculated using the Energy Offer Curve capped by the Energy Offer Curve Cap, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.6.5, Calculation of "Average Incremental Energy Cost" (AIEC).
$RTMG_{q,r,i}$	MWh	*Real-Time Metered Generation*—The Resource's metered generation for the Settlement Interval *i*.
$LSL_{q,r,i}$	MW	*Low Sustained Limit*— The low sustainable limit of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP.
$VSSVARAMT_{q,r,i}$	$	*Voltage Support Service var Amount by interval*—The payment to the QSE for the VSS provided by Generation Resource for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments.
$VSSEAMT_{q,r,i}$	$	*Voltage Support Service Energy Amount by interval*—The lost opportunity payment to the QSE for ERCOT-directed VSS from the Generation Resource for the 15-minute Settlement Interval *i*. See Section 6.6.7.1, Voltage Support Service Payments.
$EMREAMT_{q,r,i}$	$	*Emergency Energy Amount by interval*—The payment to the QSE as additional compensation for the additional energy produced by the Generation Resource in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval *i*. See Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval within the hour that is identified as a QSE-Clawback Interval.

5.7.2 RUC Clawback Charge

(1) A QSE for a Resource shall pay a RUC Clawback Charge for the Operating Day if the RUC Guarantee is less than the sum of:

(a) RUC Minimum-Energy Revenue calculated in Section 5.7.1, RUC Make-Whole Payment;

(b) Revenue Less Cost Above LSL During RUC-Committed Hours calculated in Section 5.7.1.3, Revenue Less Cost Above LSL During RUC-Committed Hours; and

(c) Revenue Less Cost During QSE-Clawback Intervals calculated in Section 5.7.1.4, Revenue Less Cost During QSE Clawback Intervals.

(2) The amount of the RUC Clawback Charge is a percentage of the difference calculated in subsection (1), above. Whether or not the QSE submits a Three-Part Supply Offer for a Resource in the DAM determines the clawback percentage. If the QSE submitted a validated Three-Part Supply Offer for the Resource into the DAM, then the clawback percentage in RUC-Committed Hours is 50% and the clawback percentage in QSE Clawback Intervals is 0%. If not, then the clawback percentage in RUC-Committed Hours is 100% and the clawback percentage in QSE Clawback Intervals is 50%.

(3) If EECP is in effect for any hour that a Resource is RUC-committed, then in all RUC-Committed Hours of the Operating Day the clawback percentage is 0% if the QSE submitted a validated Three-Part Supply Offer for the Resource into the DAM and 50% otherwise.

(4) The RUC Clawback Charge for a Resource, including RMR units, for each Operating Day is allocated evenly over the RUC-Committed Hours for that Resource.

(5) For each RUC-Committed Resource, the RUC Clawback Charge for each RUC-Committed Hour of the Operating Day is calculated as follows:

If $(\text{RUCMEREV}_{q,r,d} + \text{RUCEXRR}_{q,r,d} - \text{RUCG}_{q,r,d}) > 0$,

Then, $\text{RUCCBAMT}_{q,r,h} = [(\text{RUCMEREV}_{q,r,d} + \text{RUCEXRR}_{q,r,d} - \text{RUCG}_{q,r,d}) * \text{RUCCBFR}_{q,r,d} + \text{RUCEXRQC}_{q,r,d} * \text{RUCCBFC}_{q,r,d}]/\text{RUCHR}_{q,r,d}$

Otherwise, $\text{RUCCBAMT}_{q,r,h} = [\text{Max}(0, \text{RUCMEREV}_{q,r,d} + \text{RUCEXRR}_{q,r,d} + \text{RUCEXRQC}_{q,r,d} - \text{RUCG}_{q,r,d}) * \text{RUCCBFC}_{q,r,d}] / \text{RUCHR}_{q,r,d}$

The above variables are defined as follows:

Variable	Unit	Definition
$RUCCBAMT_{q,r,h}$	$	*RUC Clawback Charge*—The RUC Clawback Charge to a QSE for a Resource as described in Section 5.7.2, RUC Clawback Charge, for each RUC-Committed Hour of the Operating Day for that Resource.
$RUCG_{q,r,d}$	$	*RUC Guarantee*—The sum of the Resource's eligible Startup Costs and Minimum-Energy Costs during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.1, RUC Guarantee.
$RUCMEREV_{q,r,d}$	$	*RUC Minimum-Energy Revenue*—The sum of the energy revenues for the Resource's generation up to LSL during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.2, RUC Minimum-Energy Revenue.
$RUCEXRR_{q,r,d}$	$	*Revenue Less Cost Above LSL During RUC-Committed Hours*—The sum of the total revenue for the Resource above the LSL less the cost during all RUC-Committed Hours, for the Operating Day. See Section 5.7.1.3, Revenue Less Cost Above LSL During RUC-Committed Hours.
$RUCEXRQC_{q,r,d}$	$	*Revenue Less Cost from QSE-Clawback Intervals*—The sum of the profits during QSE-Clawback Intervals, for the Operating Day. See Section 5.7.1.4, Revenue Less Cost During QSE Clawback Intervals.
$RUCCBFR_{q,r,d}$	none	*RUC Claw-Back Factor for RUC-Committed Hours*—The Resource's Claw-Back Factor for RUC-Committed Hours, which is 50% if a Three-Part Supply Offer was submitted and 100% otherwise. During EECP conditions the Resource's clawback factor for RUC-Committed Hours is 0% if a Three-Part Supply Offer was submitted and 50% otherwise.
$RUCCBFC_{q,r,d}$	none	*RUC Claw-Back Factor for QSE Clawback intervals*— The Resource's clawback factor for QSE Clawback Intervals, which is 0% if a Three-Part Supply Offer was submitted and 50% otherwise.
$RUCHR_{q,r,d}$	none	*RUC Hour* – The total number of RUC-Committed Hours, for the Resource for the Operating Day.
q	none	A QSE.
r	none	A RUC-committed Generation Resource.
d	none	An Operating Day containing the RUC-commitment.
h	none	An hour in the RUC-commitment period.

5.7.3 Payment When ERCOT Decommits a QSE -Committed Resource

(1) If ERCOT decommits a QSE-committed Resource during the RUC process earlier than its scheduled shutdown within the Operating Day, then no compensation is due to the affected QSE from ERCOT.

(2) If ERCOT decommits a QSE committed Resource that is not scheduled to shutdown within the Operating Day, then ERCOT shall pay the affected QSE an amount as calculated below for the hours of decommitment. The number of continuous decommitted hours used in the calculation are the hours beginning with the first decommitted hour until the earlier of:

(a) The hour ERCOT determines that the Resource may again be at LSL; and

(b) The end of the last hour of the Operating Day.

(3) If ERCOT decommits a QSE-committed Resource not scheduled to shutdown within the Operating Day, and the decommitment period spans more than one Operating Day, the RUC Decommitment Payment shall be calculated and paid in the Operating Day in which the RUC Decommitment originated. The number of continuous decommitted hours used in the calculation are the hours beginning with the first decommitted hour until the end of the last hour of the Operating Day in which the RUC Decommitment originated.

(4) The payment for a RUC decommitment instruction for a Resource, including RMR units, is calculated for each hour as follows:

$$\text{RUCDCAMT}_{q,r,h} = (-1) * \text{Max}\left(0, \left(\text{SUPR}_{q,r,s} - \sum_{i}\left(\text{Max}\left(0, \text{MEPR}_{q,r,i} - \text{RTSPP}_{p,i}\right) * \left(\text{LSL}_{q,r,i} * (1/4)\right)\right)\right)\right) / \text{NCDCHR}_{q,r,h}$$

Where:
If the QSE submitted a validated Three-Part Supply Offer,

Then, $\text{SUPR}_{q,r,s} = \text{SUO}_{q,r,s}$

$\text{MEPR}_{q,r,i} = \text{MEO}_{q,r,i}$

Otherwise, $\text{SUPR}_{q,r,s} = \text{SUCAP}_{q,r,s}$

$\text{MEPR}_{q,r,i} = \text{MECAP}_{q,r,i}$

If QSE verifiable startup and minimum-energy costs for the Resource are on file,

Then, $\text{SUCAP}_{q,r,s}$ = verifiable startup costs$_{q,r,s}$

$\text{MECAP}_{q,r,i}$ = verifiable minimum-energy costs$_{q,r,i}$

Otherwise, $\text{SUCAP}_{q,r,s} = \text{RCGSC}_{s}$

$\text{MECAP}_{q,r,i} = \text{RCGMEC}_{i}$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RUCDCAMT}_{q,r,h}$	$	*RUC De-commitment Payment Amount*—The payment to the QSE for the Resource that was de-committed by ERCOT but that was not scheduled to shut down in the Operating Day, for each decommitted hour of the Operating Day.
$\text{SUPR}_{q,r,s}$	$/Start	*Startup Price per start*—The settlement price for the start *s*.
$\text{SUO}_{q,r,s}$	$/Start	*Startup Offer per start*—Represents an offer for all costs incurred by a Generation Resource in starting up and reaching breaker close, as indicated by a telemetered Resource status of On-Line.
$\text{SUCAP}_{q,r,s}$	$/Start	*Startup Cap*—The amount used as startup costs if the QSE did not submit a

Variable	Unit	Definition
		validated Three-Part Supply Offer. The cap is the RCGSC unless ERCOT has approved verifiable unit-specific startup costs for that Resource, in which case the startup cap is the verifiable unit-specific startup cost. See Section 5.6.1, Verifiable Costs for more information on verifiable costs.
$RCGSC_s$	$/Start	*Resource Category Generic Startup Cost*—The Generic Startup Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$MEPR_{q,r,I}$	$/MWh	*Minimum-Energy Price*—The settlement price for minimum energy for the Settlement Interval *i*.
$MEO_{q,r,i}$	$/MWh	*Minimum-Energy Offer*—Represents an offer for the costs incurred by a Resource in producing energy at the Resource's LSL for the Settlement Interval *i*.
$MECAP_{q,r,i}$	$/MWh	*Minimum Energy Cap*— The amount used for minimum-energy costs if the QSE did not submit a validated Three-Part Supply Offer. The cap is the RCGMEC unless ERCOT has approved verifiable unit-specific minimum energy costs for that Resource, in which case the Minimum-Energy cap is the verifiable unit-specific minimum energy cost. See Section 5.6.1, Verifiable Costs, for more information on verifiable costs.
$RCGMEC_i$	$/MWh	*Resource Category Generic Minimum Energy Cost*—The Generic Minimum Energy Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.
$LSL_{q,r,i}$	MW	*Low Sustained Limit*— The low sustainable limit of Generation Resource *r* represented by QSE *q* for the hour that includes the Settlement Interval *i*, as submitted in the COP.
$RTSPP_{p,i}$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Resource's Settlement Point for the Settlement Interval *i*.
$NCDCHR_{q,r,h}$	none	*Number of Continuous De-committed Hours*— The number of continuous decommitment hours within an Operating Day.
q	none	A QSE.
r	none	A RUC-decommitted Generation Resource.
h	none	An hour in the RUC Decommitment period.
p	none	A Resource Node Settlement Point.
s	none	A Start.
i	none	A 15-minute Settlement Interval within the hour that includes an ERCOT De-commitment.

5.7.4 RUC Make-Whole Charges

(1) All QSEs that were capacity-short in each RUC will be charged for that shortage, as described in Section 5.7.4.1, RUC Capacity-Short Charge, below. If the revenues from the charges under Section 5.7.4.1 are not enough to cover all RUC Make-Whole Payments for a Settlement Interval, then the difference will be uplifted to all QSEs on a Load Ratio Share basis, as described in Section 5.7.4.2, RUC Make-Whole Uplift Charge, below.

(2) To determine whether a QSE is capacity-short, the WGR Production Potential, as described in Section 4.2.2, Wind-Powered Generation Resource Production Potential, for

a WGR used in the corresponding RUC is considered the available capacity of the WGR when determining responsibility for the corresponding RUC charges, regardless of the Real-Time output of the WGR.

(3) On a monthly basis, within 10 days after the Initial Settlement of the last day of the month has been completed, ERCOT shall post on the MIS Secure Area the total RUC Make-Whole Charges and RUC Clawback Payments, by Settlement Interval, by QSE capacity-shortfall and by amount uplifted.

5.7.4.1 RUC Capacity-Short Charge

The dollar amount charged to each QSE, due to capacity shortfalls for a particular RUC, for a 15-minute Settlement Interval, is the QSE's shortfall ratio share multiplied by the total RUC Make-Whole Payments, including amounts for RMR Units, to all QSEs for that RUC, subject to a cap. The cap on the charge to each QSE is two multiplied by the total RUC Make-Whole Payments, including amounts for RMR Units, for all QSEs multiplied by that QSE's capacity shortfall for that RUC process divided by the total capacity of all RUC-Committed Resources during that Settlement Interval for the RUC process. That dollar amount charged to each QSE is calculated as follows:

$$\text{RUCCSAMT}_{ruc,i,q} = (-1) * \text{Max}\,[(\text{RUCSFRS}_{ruc,i,q} * \text{RUCMWAMTRUCTOT}_{ruc,h}), (2 * \text{RUCSF}_{ruc,i,q} * \text{RUCMWAMTRUCTOT}_{ruc,h} / \text{RUCCAPTOT}_{ruc,h})] / 4$$

Where:

$$\text{RUCMWAMTRUCTOT}_{ruc,h} = \sum_{q} \sum_{r} \text{RUCMWAMT}_{ruc,q,r,h}$$

$$\text{RUCCAPTOT}_{ruc,h} = \sum_{r} \text{HSL}_{ruc,h,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RUCCSAMT}_{ruc,i,q}$	\$	*RUC Capacity-Short Amount*—The charge to a QSE, due to capacity shortfall for a particular RUC process, for the 15-minute Settlement Interval.
$\text{RUCMWAMTRUCTOT}_{ruc,h}$	\$	*RUC Make-Whole Amount Total per RUC*—The sum of RUC Make-Whole Payments for a particular RUC process, including amounts for RMR Units, for the hour that includes the 15-minute Settlement Interval.
$\text{RUCMWAMT}_{ruc,q,r,h}$	\$	*RUC Make-Whole Payment*—The RUC Make-Whole Payment to the QSE for a Resource, for a particular RUC process, for the hour that includes the 15-minute Settlement Interval. See Section 5.7.1, RUC Make-Whole Payment.
$\text{RUCSFRS}_{ruc,i,q}$	none	*RUC Shortfall Ratio Share*—The ratio of the QSE's capacity shortfall to

Variable	Unit	Definition
		the sum of all QSEs' capacity shortfalls for a particular RUC process, for the 15-minute Settlement Interval. See Section 5.7.4.1.1, Capacity Shortfall Ratio Share.
$\text{RUCSF}_{ruc,i,q}$	MW	*RUC Shortfall*—The QSE's capacity shortfall for a particular RUC process for the 15-minute Settlement Interval. See formula in Section 5.7.4.1.1, Capacity Shortfall Ratio Share.
$\text{RUCCAPTOT}_{ruc,h}$	MW	*RUC Capacity Total*—The sum of the HSLs of all RUC-committed Resources for a particular RUC process, for the hour that includes the 15-minute Settlement Interval. See formula in Section 5.7.4.1.1, Capacity Shortfall Ratio Share.
$\text{HSL}_{ruc,h,r}$	MW	*High Sustained Limit*— A High Sustainable limit of a Generation Resource as defined in Section 2, Definitions and Acronyms, for the hour that includes the Settlement Interval *i*.
ruc	none	The RUC process for which the RUC Capacity-Short Charge is calculated.
i	none	A 15-minute Settlement Interval.
q	none	A QSE.
h	none	The hour that includes the Settlement Interval *i*.
r	none	A Generation Resource that is RUC-committed for the hour that includes the Settlement Interval *i*, as a result of a particular RUC process.

5.7.4.1.1 Capacity Shortfall Ratio Share

(1) In calculating the amount short for each QSE, the QSE must be given a capacity credit for its WGRs based on the HSL values entered into the COP by the QSE just prior to the RUC execution. For WGRs, ERCOT shall use for settlement purposes the COP and Trades Snapshot prior to the RUC regardless of Real-Time capacity or actual generation. Therefore, the HASLSNAP and HASLADJ variables used below shall be equal to the HSL values entered into the QSE's COP submitted prior to the RUC for WGRs.

(2) In calculating the amount short for each QSE, the QSE must be given a capacity credit for non-wind Resources that were given notice of decommitment within the two hours before the Operating Hour as a result of the RUC process by setting the HASLSNAP and HASLADJ variables used below equal to the HASLSNAP value for the Resource immediately before the decommitment instruction was given.

(3) In calculating the short amount for each QSE, if the HASL for a Resource was credited to the QSE during the RUC snapshot but the Resource experiences a Forced Outage within two hours before the start of the Settlement Interval, then the HASL for that Resource is also credited to the QSE in the HASLADJ.

(4) In calculating the short amount for each QSE, if the DCIMPSNAP was credited to the QSE during the RUC snapshot but the entire DC Tie experiences a Forced Outage within two hours before the start of the Settlement Interval, then the DCIMPSNAP is also credited to the QSE in the DCIMPADJ.

(5) The capacity shortfall ratio share of a specific QSE for a particular RUC process is calculated, for a 15-minute Settlement Interval, as follows:

$$\text{RUCSFRS}_{ruc,i,q} = \text{RUCSF}_{ruc,i,q} / \text{RUCSFTOT}_{ruc,i}$$

Where:

$$\text{RUCSFTOT}_{ruc,i} = \sum_{q} \text{RUCSF}_{ruc,i,q}$$

(6) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval is:

$$\text{RUCSF}_{ruc,i,q} = \text{Max } (0, \text{Max } (\text{RUCSFSNAP}_{q,i}, \text{RUCSFADJ}_{q,i}) - \sum_{z \text{ is prior to } ruc} \text{RUCCAPCREDIT}_{q,i,z})$$

(7) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval, as measured at the snapshot, is:

$$\text{RUCSFSNAP}_{q,i} = \text{Max } (0, ((\sum_{p} \text{RTAML}_{q,p,i} * 4) + \sum_{p} \text{RTDCEXP}_{q,p,i} - \text{RUCCAPSNAP}_{q,i}))$$

(8) The amount of capacity that a QSE had according to the RUC snapshot for a 15-minute Settlement Interval.

$$\text{RUCCAPSNAP}_{q,i} = \sum_{r} \text{HASLSNAP}_{q,r,h} + (\text{RUCCPSNAP}_{q,h} - \text{RUCCSSNAP}_{q,h}) + (\sum_{p} \text{DAEP}_{q,p,h} - \sum_{p} \text{DAES}_{q,p,h}) + (\sum_{p} \text{RTQQEPSNAP}_{q,p,i} - \sum_{p} \text{RTQQESSNAP}_{q,p,i}) + \sum_{p} \text{DCIMPSNAP}_{q,p,i}$$

(9) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval, as measured at Real Time, is:

$$\text{RUCSFADJ}_{q,i} = \text{Max } (0, ((\sum_{p} \text{RTAML}_{q,p,i}) * 4) + \sum_{p} \text{RTDCEXP}_{q,p,i} - \text{RUCCAPADJ}_{q,i})$$

(10) The amount of capacity that a QSE had in Real Time for a 15-minute Settlement Interval.

$$RUCCAPADJ_{q,i} = \sum_{r} HASLADJ_{q,r,h} + (RUCCPADJ_{q,h} - RUCCSADJ_{q,h}) + (\sum_{p} DAEP_{q,p,h} - \sum_{p} DAES_{q,p,h}) + (\sum_{p} RTQQEPADJ_{q,p,i} - \sum_{p} RTQQESADJ_{q,p,i}) + \sum_{p} DCIMPADJ_{q,p,i}$$

(11) The above variables are defined as follows:

Variable	**Unit**	**Definition**
$RUCSFRS_{ruc,i,q}$	none	*RUC Shortfall Ratio Share*—The ratio of the QSE's capacity shortfall to the sum of all QSEs' capacity shortfalls, for the RUC process, for the 15-minute Settlement Interval.
$RUCSF_{ruc,i,q}$	MW	*RUC Shortfall*—The QSE *q*'s capacity shortfall for the RUC process for the 15-minute Settlement Interval.
$RUCSFTOT_{ruc,i}$	MW	*RUC Shortfall Total-The sum of all QSEs' capacity shortfalls,* for a RUC process, *for a 15-minute Settlement Interval.*
$RUCSFSNAP_{q,i}$	MW	*RUC Shortfall at Snapshot*—The QSE *q*'s capacity shortfall according to the snapshot for the RUC process for the 15-minute Settlement Interval.
$RUCSFADJ_{q,i}$	MW	*RUC Shortfall at Adjustment Period*—The QSE *q*'s adjustment period capacity shortfall for the 15-minute Settlement Interval.
$RUCCAPCREDIT_{q,i,z}$	MW	*RUC Capacity Credit by QSE*—The capacity credit resulting from capacity paid through the RUC Capacity-Short Charge for the 15-minute Settlement Interval.
$RTAML_{q,p,i}$	MWh	*Real-Time Adjusted Metered Load*—The QSE *q*'s Adjusted Metered Load at the Settlement Point *p* for the 15-minute Settlement Interval.
$RUCCAPSNAP_{q,i}$	MW	*RUC Capacity Snapshot at time of RUC* -The amount of the QSE's calculated capacity in the COP and Trades Snapshot for a 15-minute Settlement Interval.
$HASLSNAP_{q,r,h}$	MW	*High Ancillary Services Limit at Snapshot*—The High Ancillary Services Limit of the Resource *r* represented by the QSE *q*, according to the COP and Trades Snapshot for the RUC process for the hour that includes the 15-minute Settlement Interval.
$RTDCEXP_{q,p}$	MW	*Real-Time DC Export per QSE per Settlement Point*—The aggregated DC Tie Schedule through DC Tie *p* submitted by QSE *q* that is under the "Oklaunion Exemption" as an exporter from the ERCOT area, for the 15-minute Settlement Interval.
$DCIMPADJ_{q,p}$	MW	*DC Import per QSE per Settlement Point*—The approved aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p* according to the adjustment period Snapshot, for the 15-minute Settlement Interval.
$DCIMPSNAP_{q,p}$	MW	*DC Import per QSE per Settlement Point*—The approved aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, according to the Snapshot for the RUC process for the hour that includes the 15-minute Settlement Interval.
$RUCCPSNAP_{q,h}$	MW	*RUC Capacity Purchase at Snapshot*—The QSE *q*'s Capacity purchase, according to the COP and Trades Snapshot for the RUC process for the hour that includes the 15-minute Settlement Interval.
$RUCCSSNAP_{q,h}$	MW	*RUC Capacity Sale at Snapshot*—The QSE *q*'s capacity sale, according to the COP and Trades Snapshot for the RUC process for the hour that includes the 15-minute Settlement Interval.
$RUCCAPADJ_{q,i}$	MW	*RUC Capacity Snapshot during Adjustment Period*-The amount of the QSE's calculated capacity in the RUC according to the COP and Trades Snapshot at the

Variable	Unit	Definition
		end of the Adjustment Period for a 15-minute Settlement Interval
$HASLADJ_{q,r,h}$	MW	*High Ancillary Services Limit at Adjustment Period* - The High Ancillary Services Limit of the Resource *r* represented by the QSE *q*, according to the adjustment period snapshot, for the hour that includes the 15-minute Settlement Interval.
$RUCCPADJ_{q,h}$	MW	*RUC Capacity Purchase at Adjustment Period*—The QSE *q*'s capacity purchase, according to the Adjustment Period COP and Trades Snapshot for the hour that includes the 15-minute Settlement Interval.
$RUCCSADJ_{q,h}$	MW	*RUC Capacity Sale at Adjustment Period*—The QSE *q*'s capacity sale, according to the Adjustment Period COP and Trades Snapshot for the hour that includes the 15-minute Settlement Interval.
$DAEP_{q,p,h}$	MW	*Day-Ahead Energy Purchase*—The QSE *q*'s energy purchased in the DAM at the Settlement Point *p* for the hour that includes the 15-minute Settlement Interval.
$DAES_{q,p,h}$	MW	*Day-Ahead Energy Sale*—The QSE *q*'s energy sold in the DAM at the Settlement Point *p* for the hour that includes the 15-minute Settlement Interval.
$RTQQEPSNAP_{q,p,i}$	MW	*QSE-to-QSE Energy Purchase by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval, in the COP and Trades Snapshot.
$RTQQESSNAP_{q,p,i}$	MW	*QSE-to-QSE Energy Sale by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval, in the COP and Trades Snapshot.
$RTQQEPADJ_{q,p,i}$	MW	*QSE-to-QSE Energy Purchase by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval, in the last COP and Trades Snapshot at the end of the Adjustment Period for that Settlement Interval.
$RTQQESADJ_{q,p,i}$	MW	*QSE-to-QSE Energy Sale by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval, in the last COP and Trades Snapshot at the end of the Adjustment Period for that Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource that is QSE-committed or RUC-decommitted (subject to paragraphs 1 and 2 above) for the Settlement Interval.
z	none	A previous RUC process for the Operating Day.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
ruc	none	The RUC process for which this Capacity Shortfall Ratio Share is calculated.

5.7.4.1.2 RUC Capacity Credit

A QSE that is charged for a capacity shortfall in one RUC process gets a capacity credit equal to the minimum of the QSE's RUC shortfall (MW) or the total RUC capacity purchased multiplied by the QSE's shortfall ratio share. The capacity credit to be used in future RUC processes for the same 15-minute Settlement Interval is calculated as follows:

$$\text{RUCCAPCREDIT}_{ruc,i,q} = \text{Min}\ [\text{RUCSF}_{ruc,i,q}, (\text{RUCCAPTOT}_{ruc,h} * \text{RUCSFRS}_{ruc,i,q})]$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RUCCAPCREDIT}_{ruc,i,q}$	MW	*RUC Capacity Credit by QSE*—The capacity credit resulting from capacity paid through the RUC Capacity-Short Charge for the 15-minute Settlement Interval.
$\text{RUCSF}_{ruc,i,q}$	MW	*RUC Shortfall*—The QSE's capacity shortfall for the RUC process for the 15-minute Settlement Interval.
$\text{RUCSFRS}_{ruc,i,q}$	none	*RUC Shortfall Ratio Share*—The ratio of the QSE's capacity shortfall to the sum of all QSEs' capacity shortfalls, for the RUC process, for the 15-minute Settlement Interval.
$\text{RUCCAPTOT}_{ruc,h}$	MW	*RUC Capacity Total*—The total capacity of all RUC-committed Resources during the RUC process, for the hour that includes the 15-minute Settlement Interval.
q	none	A QSE.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
ruc	none	The RUC process for which this RUC Capacity Credit is calculated.

5.7.4.2 RUC Make-Whole Uplift Charge

If the revenues from the charges under Section 5.7.4.1, RUC Capacity-Short Charge, are not enough to cover all RUC Make-Whole Payments, including amounts for RMR Units, for a 15-minute Settlement Interval, then the difference will be uplifted to all QSEs on a Load Ratio Share basis, as a RUC Make-Whole Uplift Charge, calculated as follows:

$$\text{LARUCAMT}_{q,i} = (-1) * (\text{RUCMWAMTTOT}_{h} / 4 + \text{RUCCSAMTTOT}_{i}) * \text{LRS}_{q,i}$$

Where:

$$\text{RUCMWAMTTOT}_{h} = \sum_{ruc} \text{RUCMWAMTRUCTOT}_{ruc,h}$$

$$\text{RUCCSAMTTOT}_{i} = \sum_{ruc} \sum_{q} \text{RUCCSAMT}_{ruc,i,q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{LARUCAMT}_{q,i}$	$	*RUC Make-Whole Uplift Charge*—The amount owed from the QSE based on Load Ratio Share, for the 15-minute Settlement Interval.
RUCMWAMTTOT_{h}	$	*RUC Make-Whole Amount Total*—The sum of RUC Make-Whole Payments for all RUC processes, including amounts for RMR Units, for the hour that includes the 15-minute Settlement Interval.
$\text{RUCMWAMTRUCTOT}_{ruc,h}$	$	*RUC Make-Whole Amount Total per RUC*—The sum of RUC Make-Whole Payments for a particular RUC process, including payments for RMR Units, for the hour that includes the 15-minute Settlement Interval.
RUCCSAMTTOT_{i}	$	*RUC Capacity Amount Total*—The sum of RUC Capacity-Short Charges for all QSEs and RUC processes, including payments for RMR Units, for the 15-minute Settlement Interval.
$\text{RUCCSAMT}_{ruc,i,q}$	$	*RUC Capacity-Short Amount*—The charge to a QSE, due to capacity shortfall for a particular RUC process, for the 15-minute Settlement Interval.
$\text{LRS}_{q,i}$	none	*Load Ratio Share*—The ratio of Adjusted Metered Load to the total ERCOT Adjusted Metered Load for the 15-minute Settlement Interval. See Section 6.6.2, Load Ratio Share, item (2).
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
ruc	none	A RUC Process.
q	none	A QSE.

5.7.5 RUC Clawback Payment

ERCOT shall pay the revenues from all RUC Clawback Charges, including amounts for RMR units, in a 15-minute Settlement Interval to all QSEs, on a Load Ratio Share basis, as the RUC Clawback Payment. The RUC Clawback Payment is calculated as follows for each QSE for each 15-minute Settlement Interval:

$$\text{LARUCCBAMT}_{q,i} = (-1) * (\text{RUCCBAMTTOT}_{h} / 4 * \text{LRS}_{q,i})$$

Where:

$$\text{RUCCBAMTTOT}_{h} = \sum_{q} \sum_{r} \text{RUCCBAMT}_{q,r,h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LARUCCBAMT_{q,i}$	$	*RUC Clawback Payment*—The RUC Make-Whole Clawback Payment to a QSE to uplift RUC Make-Whole Clawback Charges received, for a 15-minute Settlement Interval.
$RUCCBAMTTOT_{h}$	$	*RUC Clawback Charge Total* —The sum of RUC Clawback Charges to all QSEs, including amounts for RMR Units, for hour that includes the 15-minute Settlement Interval.
$LRS_{q,i}$	none	*Load Ratio Share*—The ratio of Adjusted Metered Load to the total ERCOT Adjusted Metered Load for the 15-minute Settlement Interval. See Section 6.6.2, Load Ratio Share, item (2).
$RUCCBAMT_{q,r,h}$	$	*RUC Clawback Charge*—The RUC Clawback Charge to the QSE *q* for the Resource *r*, for the hour that includes the 15-minute Settlement Interval.
q	None	A QSE.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
r	none	A Generation Resource.

5.7.6 RUC Decommitment Charge

ERCOT shall charge each QSE a RUC Decommitment Charge, on a Load Ratio Share basis, all revenues paid as a result of RUC Decommitment Payments, including amounts for RMR units. The RUC Decommitment Charge for a 15-minute Settlement Interval is calculated as follows:

$$LARUCDCAMT_{q,i} = (-1) * [(RUCDCAMTTOT_{h} / 4) * LRS_{q,i}]$$

Where:

$$RUCDCAMTTOT_{h} = \sum_{q} \sum_{r} RUCDCAMT_{q,r,h}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LARUCDCAMT_{q,i}$	$	*RUC Decommitment Charge*—The RUC Decommitment Charge to a QSE, for a 15-minute Settlement Interval.
$RUCDCAMTTOT_{h}$	$	*RUC Decommitment Charge Total*—The sum of RUC Decommitment Payments to all QSEs, including amounts for RMR Units, for the hour that includes the 15-minute Settlement Interval.
$LRS_{q,i}$	none	*Load Ratio Share*—The ratio of Adjusted Metered Load to the total ERCOT Adjusted Metered Load for the 15-minute Settlement Interval. See Section 6.6.2, Load Ratio Share, item (2).
$RUCDCAMT_{q,r,h}$	$	*RUC Decommitment Charge* —The RUC Decommitment Charge to the QSE *q* for the Resource *r*, for the hour that includes the 15-minute Settlement Interval.
q	None	A QSE.

i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
r	None	A Generation Resource.

ERCOT Nodal Protocols

Section 6: Adjustment Period and Real-Time Operations

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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6 ADJUSTMENT PERIOD AND REAL-TIME OPERATIONS

6.1 Introduction

(1) This Section addresses the following components: the Adjustment Period and Real-Time Operations, including Emergency Operations.

(2) The Adjustment Period provides each QSE the opportunity to adjust its trades, Self-Schedules, and Resource commitments as more accurate information becomes available under Section 6.4, Adjustment Period. During the Adjustment Period, ERCOT continues to evaluate system sufficiency and security by use of Hour-Ahead Reliability Unit Commitment processes, as described in Section 5, Transmission Security Analysis and Reliability Unit Commitment. Under certain conditions during the Adjustment Period, ERCOT may also open one or more Supplemental Ancillary Service Markets (SASMs), as described in Section 6.4.8.2, Supplemental Ancillary Services Market.

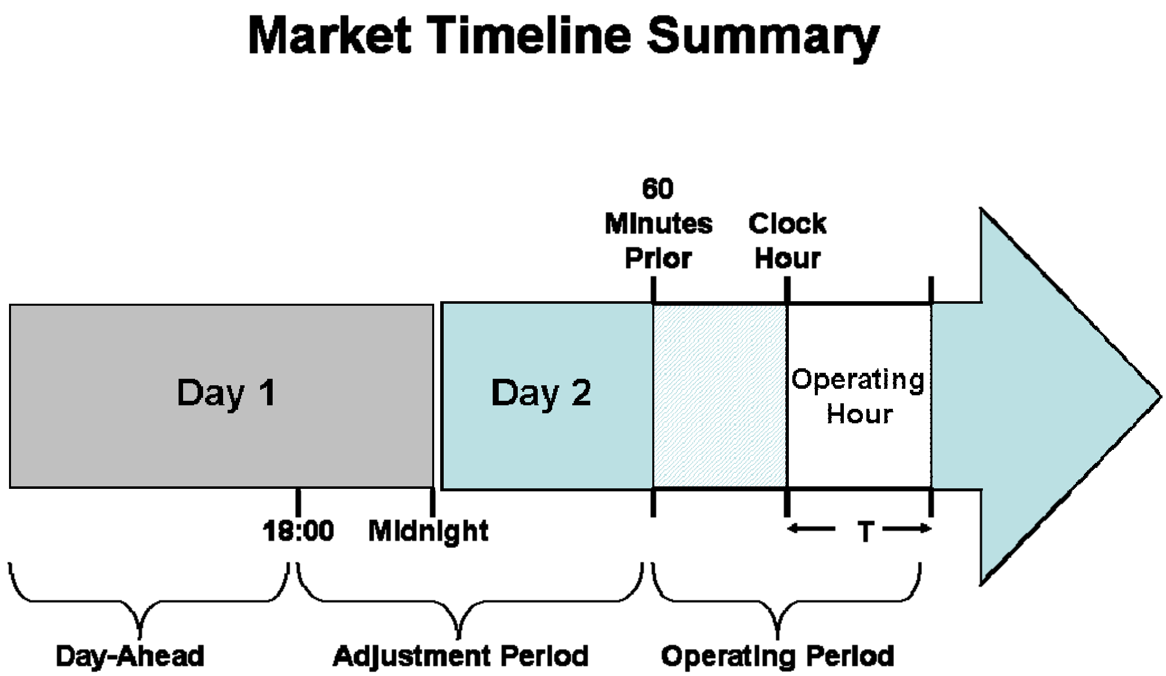
(3) During Real-Time operations, ERCOT dispatches Resources under normal system conditions and behavior based on economics and reliability to match system Load with On-Line generation while observing Resource and transmission constraints. The Security Constrained Economic Dispatch (SCED) process produces Base Points for Resources. ERCOT uses the Base Points from the SCED process and uses the deployment of Regulation Up (Reg-Up), Regulation Down (Reg-Down), Responsive Reserve, and Non-Spinning Reserve (Non-Spin) to control frequency and solve potential reliability issues.

(4) Under Emergency Conditions, as described in Section 6.5.9, Emergency Operations, ERCOT may implement manual procedures and must keep the Market Participants informed of the status of the system.

(5) Real-Time energy settlements use Real-Time Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a 15-minute Settlement Interval, using the LMPs from all of the executions of SCED in the Settlement Interval. In contrast, the DAM energy settlements will use DAM Settlement Point Prices that are calculated for Resource Nodes, Load Zones, and Hubs for a one-hour Settlement Interval.

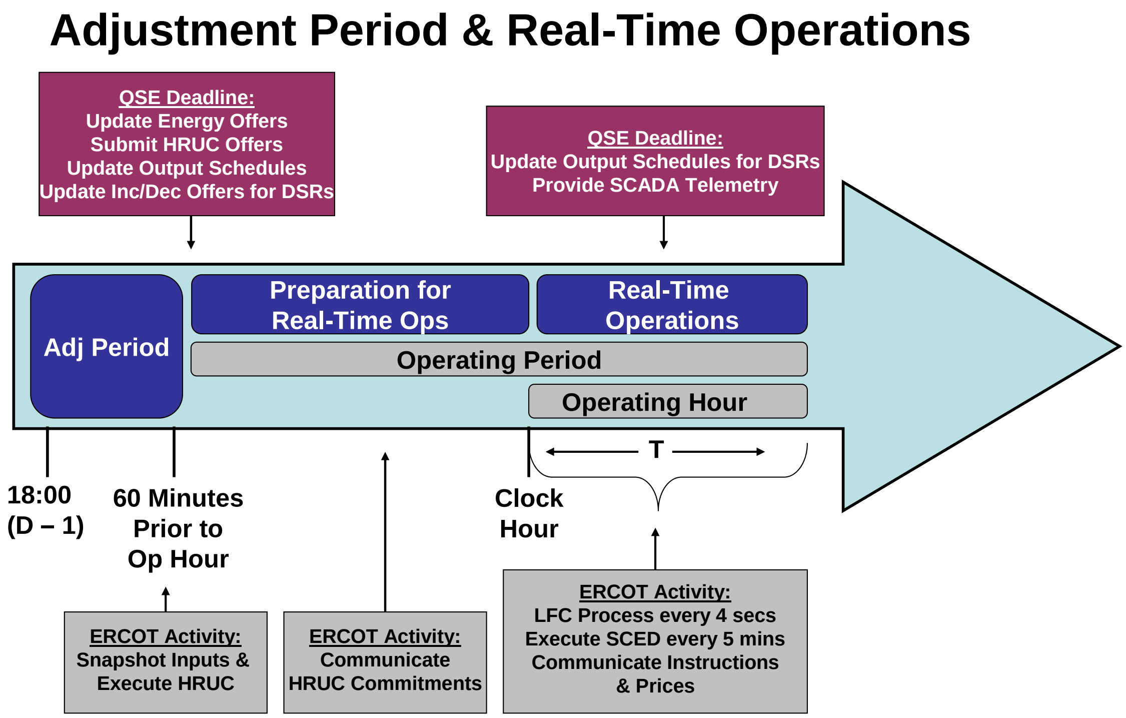
6.2 Market Timeline Summary

The figure below is a high-level summary of the overall market timeline:



6.3 Adjustment Period and Real-Time Operations Timeline

(1) The figure below highlights the major activities that occur in the Adjustment Period and Real-Time operations:



(2) Activities for the Adjustment Period begin at 1800 in the Day-Ahead and end one full hour before the start of the Operating Hour. The figure above is intended to be only a general guide and not controlling language, and any conflict between this figure and another section of the Protocols is controlled by the other section.

(3) All Real-Time LMPs, SASM MCPCs, and Real-Time Settlement Point Prices are final at 1600 of the next Business Day after the Operating Day. After Real-Time LMPs, SASM MCPCs, and Real-Time Settlement Point Prices are final, they cannot be changed unless the Board finds that the Real-Time LMPs, SASM MCPCs, or Real-Time Settlement Point Prices are significantly affected by a software or data error.

6.3.1 Activities for the Adjustment Period

(1) The following table summarizes the timeline for the Adjustment Period and the activities of QSEs and ERCOT. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Adjustment Period	**QSE Activities**	**ERCOT Activities**
Time = From 1800 in the Day-Ahead up to one hour before the start of the Operating Hour	Submit and update Energy Trades, Capacity Trades, Self-Schedules, and Ancillary Service Trades Submit and update Output Schedules Submit and update Incremental and Decremental Energy Offer Curves for Dynamically Scheduled Resources (DSRs) Submit and update Energy Offer Curves Update Current Operating Plan (COP) Request Resource decommitments Submit Three-Part Supply Offers for Off-Line Generation Resources Submit offers for any Supplemental Ancillary Service Markets Communicate Resource Forced Outages	Post shift schedules on the MIS Secure Area. Validate Energy Trades, Capacity Trades, Self-Schedules, and Ancillary Service Trades and identify invalid or mismatched trades. Validate Output Schedules Validate Incremental and Decremental Energy Offer Curves Validate Energy Offer Curves Validate Current Operating Plan (COP) Review and approve or reject Resource decommitments Validate Three-Part Supply Offers Publish Notice of Need to Procure Additional Ancillary Service capacity if required Validate Ancillary Service Offers At the end of the Adjustment Period snap-shot the net capacity credits for HRUC Settlement Update Short-Term Wind Power Forecast (WGRPP) Execute the Hour-Ahead Sequence Notify the QSE via the MIS Certified Area that an Energy Offer Curve or Output Schedule has not yet been submitted for a Resource as a reminder that one of the two must be submitted by the end of the Adjustment Period

6.3.2 *Activities for Real-Time Operations*

(1) Activities for Real-Time operations begin at the end of the Adjustment Period and conclude at the close of the Operating Hour.

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review and communicate HRUC commitments Snapshot the Scheduled Power Consumption for Controllable Load Resources
Before the start of each SCED run	Update Output Schedules for Dynamically Scheduled Resources (DSRs)	Validate Output Schedules for Dynamically Scheduled Resources (DSRs) Execute Real-Time Sequence
SCED run		Execute SCED
During the Operating Hour	Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update Current Operating Plan with actual Resource Status and limits and Ancillary Service Schedules Communicate Resource Forced Outages to ERCOT	Communicate all Base Points, Dispatch Instructions and LMPs for energy and Ancillary Services using ICCP or Verbal Dispatch Instructions Monitor Resource Status and identify discrepancies between Current Operating Plan and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services; Validate COP information Monitor ERCOT control performance; Distribute by ICCP, and post to the MIS Public Area, the LMPs created by each SCED process for each Resource Node , and the Settlement Point Price at each Hub and Load Zone immediately on deployment of Base Points from SCED with the time stamp the prices are effective

Operating Period	QSE Activities	ERCOT Activities
		Post SCED Shadow Prices via the MIS Public Area Post on the MIS Public Area active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) via the MIS Public Area Post the Settlement Point Prices for each Settlement Point immediately following the end of each Settlement Interval Post parameters as required by Section 6.4.8, Ancillary Services Capacity During the Adjustment Period and in Real-Time, to the MIS Secure Area

(3) At the beginning of each hour, ERCOT shall post on the MIS Secure Area the following information:

(a) Changes in ERCOT System conditions that could affect the security and dynamic transmission limits of the ERCOT System, including:

(i) Changes or expected changes, in the status of Transmission Facilities for the remaining hours of the current Operating Day and all hours of the next Operating Day, supplementing those that are already in the Outage Scheduler; and

(ii) Any conditions such as adverse weather conditions as determined from the ERCOT-designated weather service;

(b) Updated system-wide Load forecasts;

(c) The quantities of RMR Services deployed by ERCOT for each previous hour of the current Operating Day;

(d) Total ERCOT System Demand, from Real-Time operations, integrated over each Settlement Interval; and

(e) Updated Electrical Bus Load distribution factors and other information necessary to forecast Electrical Bus Loads for each hour of the current Operating Day and all hours of the next Operating Day.

6.3.3 Real-Time Timeline Deviations

ERCOT may temporarily deviate from the Real-Time deadlines but only to the extent necessary to ensure the secure operation of the ERCOT System. Temporary measures may include varying the timing requirements as specified below or omitting one or more procedures in the Real-Time

Sequence. In such an event, ERCOT shall immediately declare an Emergency Condition and notify all QSEs of the following:

(a) Details of the affected timing requirements and procedures;

(b) Details of any interim requirements;

(c) An estimate of the period for which the interim requirements apply; and

(d) Reasons for the temporary variation.

6.3.4 ERCOT Notification of Validation Rules for Real-Time

ERCOT shall provide each QSE with the information necessary to pre-validate its data for Real-Time operations including publishing validation rules for offers, bids, and trades and posting any software documentation and code that is not Protected Information to the MIS Secure Area within five Business Days after receipt by ERCOT.

6.4 Adjustment Period

6.4.1 Capacity Trade, Energy Trade, Self-Schedule, and Ancillary Service Trades

(1) A detailed explanation of Capacity Trade criteria and validations performed by ERCOT is provided in Section 4.4.1, Capacity Trades. A QSE may submit and update Capacity Trades during the Adjustment Period.

(2) A detailed explanation of Energy Trade criteria and validations performed by ERCOT is provided in Section 4.4.2, Energy Trades. A QSE may submit and update Energy Trades during the Adjustment Period and through 1430 on the day following the Operating Day for Settlement.

(3) A detailed explanation of Self-Schedule criteria and validations performed by ERCOT is provided in Section 4.4.3, Self-Schedules. A QSE may submit and update Self-Schedules during the Adjustment Period.

(4) A detailed explanation of Ancillary Service Trade criteria and validations performed by ERCOT is provided in Section 4.4.7.3, Ancillary Service Trades. A QSE may submit and update Ancillary Service Trades during the Adjustment Period.

6.4.2 Output Schedules

(1) A QSE that represents a Resource, other than an RMR Unit, must submit and maintain either an Energy Offer Curve or an Output Schedule for the Resource for all times when the Resource is On-Line.

(2) For an On-Line RMR Unit, ERCOT, in its sole discretion, shall submit either an Output Schedule or an Energy Offer Curve, considering contractual constraints on the Resource and any other adverse effects on, or implications arising from, the RMR Agreement, that may occur as the result of the Dispatch of the RMR Unit.

(3) The entry of an Energy Offer Curve for a Resource automatically nullifies the Output Schedule for that Resource and prohibits entry of future Output Schedules for that Resource for the time during which the Energy Offer Curve is in effect.

(4) For a Resource for which an Energy Offer Curve has not been submitted, the SCED process uses the Output Schedule submitted for that Resource as desired Dispatch levels for the Resource.

6.4.2.1 Output Schedules for Resources Other than Dynamically Scheduled Resources

(1) An Output Schedule for a non-DSR Resource may be submitted and updated only during the Adjustment Period. An Output Schedule for a non-DSR Resource may be submitted and updated for each five-minute interval for each Operating Hour.

(2) For a Resource that is not a DSR and that is On-Line, the following provisions apply:

(a) The Output Schedule for a Qualifying Facility (QF) not submitting an Energy Offer Curve is considered to be equal to the telemetered output of the QF at the time that the SCED runs;

(b) The Output Schedule for Intermittent Renewable Resources not submitting Energy Offer Curves is considered to be equal to the telemetered output of the Resource at the time that the SCED runs; and

(c) ERCOT shall create proxy Energy Offer Curves for the Resource under Section 6.5.7.3, Security Constrained Economic Dispatch, paragraph (3)(a).

6.4.2.2 Output Schedules for Dynamically Scheduled Resources

(1) A QSE representing a DSR may update the Output Schedule for a dispatch interval at any time before the SCED process for that interval.

(2) For a DSR that is On-Line, the following provisions apply:

(a) For an On-Line DSR for which its QSE has not submitted an Incremental and Decremental Energy Offer Curve, ERCOT shall use the Output Schedule available at the SCED snapshot for the execution of the SCED and shall assume that the scheduled MW amount in the Output Schedule is the Base Point for the DSR for that SCED interval. ERCOT shall create proxy Energy Offer Curves for the DSR under Section 6.5.7.3, Security Constrained Economic Dispatch, paragraph (3)(a).

(b) If the QSE representing a DSR submits an Incremental and Decremental Energy Offer Curve under Section 6.4.4, Incremental and Decremental Energy Offer Curves, then ERCOT shall use the Incremental and Decremental Energy Offer Curve to create proxy Energy Offer Curves for the DSR under Section 6.5.7.3(3)(b).

(c) For a DSR that is dispatched to a Base Point other than its Output Schedule for that SCED interval, the Base-Point Deviation Charge under Section 6.6.5, Generation Resource Base-Point Deviation Charge, applies:

(i) Beginning after four consecutive, complete 15-minute Settlement Intervals have occurred after the DSR is dispatched to a Base Point other than its Output Schedule; and

(ii) Ending when the DSR is no longer dispatched to a Base Point other than its Output Schedule.

(d) After the DSR is no longer dispatched to a Base Point other than its Output Schedule, the 15 MW or 15% limit, whichever is greater, under paragraph (3) of Section 6.4.2.3, Output Schedule Criteria, does not apply to the DSR until four consecutive, complete 15-minute Settlement Intervals have occurred after the DSR is no longer dispatched to a Base Point other than its Output Schedule.

6.4.2.3 Output Schedule Criteria

(1) An Output Schedule submitted by a QSE for a Resource that is not an RMR Unit and by ERCOT for an RMR Unit must include the following:

(a) The name of the Entity submitting the Output Schedule for the Resource;

(b) The name of the Resource;

(c) The desired MW output level for each five-minute interval for the Resource for all of the remaining five-minute intervals in the Operating Day for which an Energy Offer Curve has not been submitted.

(2) ERCOT must reject an Output Schedule for a Resource if an Energy Offer Curve corresponding to any period in the Output Schedule exists;

(3) For a QSE representing one or more Dynamically Scheduled Resources, the sum of all Output Schedules (excluding Ancillary Services Energy deployments, energy deployed through Dispatch Instructions, and Energy Trades) for the QSE must be within 15% or 15 MW (whichever is greater) of the aggregate telemetered DSR Load;

(4) The MW difference between Output Schedules for any two consecutive five-minute intervals must be less than ten times the SCED Up Ramp Rate for schedules showing an

increase from the prior period and the SCED Down Ramp Rate for schedules showing a decrease from the prior period.

(5) The Output Schedule for each interval in the Operating Period must be less than the Resource's HSL and must be greater than the Resource's LSL for the corresponding hour.

6.4.2.4 Output Schedule Validation

(1) A validated Output Schedule is a schedule that ERCOT has determined meets the criteria listed in Section 6.4.2.3, Output Schedule Criteria.

(2) ERCOT shall notify the QSE submitting an Output Schedule by the Messaging System if the schedule was rejected or was considered invalid for any reason. The QSE may then resubmit the schedule within the appropriate market timeline.

(3) ERCOT shall continuously validate Output Schedules and continuously display on the MIS Certified Area information that allows any QSE to view its valid Output Schedule.

(4) If a valid Output Schedule does not exist for a Resource that has a status of On-Line Dynamically Scheduled Resource at the time of SCED execution, then ERCOT shall notify the QSE and set the Output Schedule equal to the telemetered output of the Resource until a revised Output Schedule is validated.

(5) If a valid Energy Offer Curve or an Output Schedule does not exist for a non-Dynamically Scheduled Resource that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE and set the Output Schedule equal to the then current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period.

6.4.2.5 DSR Load

(1) A QSE may designate a Resource in the Current Operating Plan and through the telemetered Resource Status as a participant in the QSE's control of DSR Load under the requirements in Section 16.2.3.2, Process to Gain Approval to Follow DSR Load.

(2) Each QSE may not have more than one DSR Load.

(3) The following principles for DSR Load apply:

(a) All power signals for DSR Load must be sent to ERCOT in Real-Time by telemetry; and

(b) If a DSR Load signal is lost for any reason for a period greater than one 15-minute Settlement Interval, then ERCOT shall notify the QSE and suspend validation of Dynamically Scheduled Resource Output Schedules. If the DSR Load signal fails for more than ten consecutive hours, ERCOT shall suspend the QSE's ability to use Dynamically Scheduled Resources until the signal is reliably restored (as determined by ERCOT). If the signal failure is identified to be an ERCOT communication problem, ERCOT may not suspend the QSE's ability to use Dynamically Scheduled Resources.

6.4.3 Energy Offer Curve

(1) A detailed description of Energy Offer Curve and validations performed by ERCOT is in Section 4.4.9, Energy Offers and Bids.

(2) For an On-Line RMR Unit, ERCOT, in its sole discretion, shall submit either an Output Schedule or an Energy Offer Curve considering contractual constraints on the Resource and any other adverse effects on, or implications arising from, the RMR Agreement, that may occur as the result of the Dispatch of the RMR Unit. If ERCOT chooses to submit an Energy Offer Curve instead of an Output Schedule, the Energy Offer Curve must be based on the RMR Agreement input/output curve and the fuel budget for the RMR Unit.

(3) If a valid Energy Offer Curve or an Output Schedule does not exist for a Resource that has a status of On-Line at the end of the Adjustment Period, then ERCOT shall notify the QSE and create an Output Schedule equal to the then-current telemetered output of the Resource until an Output Schedule or Energy Offer Curve is submitted in a subsequent Adjustment Period.

6.4.4 Incremental and Decremental Energy Offer Curves

A QSE for a DSR may submit an "Incremental Energy Offer Curve" and a "Decremental Energy Offer Curve" in addition to the Output Schedule for the DSR. At every MW value of the curves, the price of the Incremental Energy Offer Curve must be greater than the Decremental Energy Offer Curve. Incremental and Decremental Energy Offer Curves are subject to the same requirements for the same criteria and validations performed by ERCOT as provided in Section 4.4.9, Energy Offers and Bids.

6.4.5 Resource Status

(1) ERCOT shall use the telemetered Resource Status for all applications requiring status of Resources during the Operating Hour, including SCED, Load Frequency Control (LFC), and Network Security Analysis processes. QSEs shall provide ERCOT with accurate telemetry of the current capability of each Resource including the Resource Status, Ramp Rates, HSL, and LSL and a text reason for any Resource where a Ramp Rate is deviating from a standard Ramp Rate curve for the Resource, or the HSL is less than, or LSL is greater than, the normal high and low limits set in Section 3.7.1, Resource Parameter Criteria.

(2) ERCOT shall perform the following validations during the Operating Period:

(a) Each QSE shall provide the Real-Time operating status of each Resource to ERCOT by telemetry using the status codes in the Current Operating Plan for Real-Time as described in Section 3.9, Current Operating Plan (COP); and

(b) Five minutes before the end of each hour, ERCOT shall identify inconsistencies between the telemetered Resource Status and the Resource Status stated in the COP for that Resource in the next hour. On detecting an inconsistency, ERCOT shall provide a notice of inconsistent Resource Status to the QSE using the Messaging System.

6.4.6 QSE-Requested Decommitment of Resources

(1) A Resource must remain committed during any RUC-Committed Interval unless the Resource has a Forced Outage.

(2) In the Operating Period, a QSE may request to decommit a Resource for any interval that is not a RUC-Committed Interval by verbally requesting ERCOT to consider its request.

(3) In the Adjustment Period, a QSE may request to decommit a Resource for any interval that is not a RUC-Committed Interval by indicating a change in unit status in the QSE's COP.

(4) A Resource cannot be decommitted for just a portion of a DAM-Committed Interval, which is a one-hour interval. If a Resource that is decommitted for a DAM-Committed Interval, that one-hour DAM-Committed Interval is excluded from the calculation of any Day-Ahead Make-Whole Payment for that Resource.

6.4.6.1 QSE Request to Decommit Resources in the Operating Period

(1) For a request made during the Operating Period to decommit a Resource, ERCOT may perform a study using Real-Time conditions to determine if ERCOT will remain n-1 secure with that Resource Off-Line. ERCOT may grant the request if analysis indicates the Resource Outage contingency results in no additional active constraints for SCED. ERCOT may only approve requests that do not have a reliability impact.

(2) If more units are requesting decommitment than can be accommodated, ERCOT shall review the requests in order of receipt.

6.4.6.2 QSE Request to Decommit Resources in the Adjustment Period

(1) To decommit an otherwise available Resource for hours other than the Operating Period, the QSE must update the COP indicating the change in Resource Status for each hour in the COP for the remaining hours in the Adjustment Period. On detection of a change from On-Line to Off-Line Available state in future hours for a Resource, ERCOT shall review all requests for decommitment using the next scheduled HRUC. The Resource must be shown as available for HRUC commitment. The next HRUC commitment must

consider the Resource's Minimum-Energy Offer excluding the Resource's Startup Offer from the Three-Part Supply Offer.

(2) If HRUC continues to require the Resource to be committed, ERCOT shall notify the QSE, using the process described in Section 5.5.3, Communication of RUC Commitments and Decommitments, that the decommitment has been denied, and the affected intervals become RUC-Committed Intervals instead of QSE-Committed Intervals for RUC Settlement purposes. The QSE must update its COP to denote the RUC-Committed Intervals.

6.4.7 Notification of Forced Outage of a Resource

In the event of a Forced Outage of a Resource, the telemetered status of the Resource automatically notifies ERCOT of the event. In the event of a Forced Outage, an impending Forced Outage, or de-rating of a Resource, the QSE shall inform ERCOT of the following:

(a) Time of expected change in Resource Status or rating;

(b) Text message describing the nature of the Forced Outage or de-rating updated as new information becomes available; and

(c) The expected minimum and maximum duration of the Forced Outage or de-rating.

6.4.8 Ancillary Services Capacity During the Adjustment Period and in Real-Time

6.4.8.1 Evaluation and Maintenance of Ancillary Service Capacity Sufficiency

(1) ERCOT shall evaluate Ancillary Service requirements and capacity sufficiency using evaluation tools including the Ancillary Services Capacity Monitor, described in Section 6.5.7.5, Ancillary Services Capacity Monitor, throughout the Adjustment Period and Operating Period.

(2) ERCOT may procure Ancillary Services in the Adjustment Period for the following reasons:

(a) Increased need of Ancillary Services capacity above that specified in the Day-Ahead;

(b) Replacement of Ancillary Services capacity that is undeliverable due to transmission constraints; or

(c) Replacement of Ancillary Services capacity due to failure to provide.

(3) A QSE may change the specific Resources supplying Ancillary Services under Section 3.9, Current Operating Plan (COP) using the QSE's Ancillary Service Schedule in the COP only if, in ERCOT's determination, that change does not adversely affect the

deliverability of the service(s) being allocated to an alternate Resource and if that change does not adversely affect the deliverability of other services previously procured by ERCOT. A QSE may not change the quantity provided of each type Ancillary Services awarded through the ERCOT procurement process or the aggregate amount of Self-Arranged Ancillary Services (by Ancillary Service type) from the DAM. On detection of a change in COP for Resources providing Ancillary Services, ERCOT shall review the impact on deliverability and communicate to the QSE if the change is not approved. The QSE must update its COP to reflect the ERCOT decision. If ERCOT does not act on the request by the beginning of the Operating Hour in which the change will take effect, the request is deemed approved.

6.4.8.1.1 ERCOT Increases to the Ancillary Services Plan

(1) If ERCOT determines in the Adjustment Period, in its sole discretion, that more Ancillary Services are needed for one or more Operating Hours than were provided in the Day-Ahead Ancillary Services Plan, it shall notify each QSE of its increased Ancillary Service Supply Obligation.

(2) ERCOT may procure more Ancillary Services through a Supplemental Ancillary Services Market, as described below in Section 6.4.8.2, Supplemental Ancillary Services Market (SASM) if the Self-Arranged Ancillary Service quantities are insufficient to meet the total Ancillary Service Supply Obligation.

(3) When a SASM has been executed in response to ERCOT increasing the Ancillary Services Plan, each QSE that purchases Ancillary Service capacity shall be charged its share of the net cost incurred for that service, in accordance with Section 6.7.3, Adjustments to Cost Allocations for Ancillary Services Procurement.

6.4.8.1.2 Replacement of Undeliverable Ancillary Service Due to Transmission Constraints

(1) The HRUC process must honor the HASL and LASL for each Resource for each hour of the RUC Study Period unless by doing so a transmission constraint exists where energy from the Resource is needed to resolve the constraint that cannot be resolved by any other means or the energy output from the Resource must be decreased such that the Resource is unable to provide the Ancillary Service capacity allocated to that Resource in the COP. In those cases, ERCOT shall provide the following information to each affected QSE with two hours' advance notice of:

 (a) The amount by which the QSE must reduce the Ancillary Services currently allocated to each affected Resource; and

 (b) The start and stop times of the reduction.

(2) Within the two-hour advance notice period, each affected QSE may do one or more of the following:

(a) Substitute capacity from other Resources represented by that QSE to meet its Ancillary Services Supply Responsibility;

(b) Substitute capacity from other QSEs using Ancillary Service Trades; or

(c) Inform ERCOT that all or part of the Ancillary Services capacity needs to be replaced.

(3) If a QSE elects to substitute capacity, ERCOT shall determine the feasibility of the substitution. If the substitution is deemed infeasible by ERCOT or the QSE informs ERCOT that the Ancillary Services capacity needs to be replaced, then ERCOT shall procure, if in its sole discretion it finds that the service is still needed, the Ancillary Services capacity required under Section 6.4.8.2, Supplemental Ancillary Services Market.

(4) If ERCOT procures additional Ancillary Services for the amount of substituted capacity that is deemed infeasible or the amount of Ancillary Services capacity that each affected QSE does not replace, then all QSEs that bought the specific Ancillary Service in the DAM are charged for their share of the net cost incurred for the Ancillary Service procured by ERCOT as part of the multiple procurement processes (DAM and SASMs) , in accordance with Section 6.7.3, Adjustments to Cost Allocations for Ancillary Services Procurement.

(5) If the QSE's Ancillary Service capacity that is undeliverable because of a transmission constraint identified by ERCOT, as set forth in (1) above, was not awarded in the DAM or any SASM (i.e., the capacity is part of Self-Arranged Ancillary Services for the hours of the RUC Study Period), then the QSE is charged for the insufficient Ancillary Service capacity the same price paid for the Ancillary Service as purchasers in the DAM paid for that time period, as determined under paragraph (4) above.

(6) If the QSE's Ancillary Service capacity that is undeliverable because of a transmission constraint identified by ERCOT, as set forth in (1) above, was awarded in the DAM or any SASM, then the QSE is not compensated for the quantity of the Ancillary Service capacity that is undeliverable.

6.4.8.1.3 Replacement of Ancillary Service Due to Failure to Provide

(1) ERCOT may procure Ancillary Services to replace those of a QSE that has failed on its Ancillary Services Supply Responsibility through a Supplemental Ancillary Services Market, as described below in Section 6.4.8.2, Supplemental Ancillary Services Market. A QSE is considered to have failed on its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's Resource-specific Ancillary Service capacity will not be available in Real-Time. This Section does not apply to a failure to provide caused by events described in Section 6.4.8.1.2, Replacement of Undeliverable Ancillary Service Due to Transmission Constraints.

(2) Within a time frame acceptable to ERCOT, each affected QSE may either substitute capacity to meet its Ancillary Services Supply Responsibility or inform ERCOT that the Ancillary Services capacity needs to be replaced. If a QSE elects to substitute capacity, ERCOT shall determine the feasibility of the substitution. If the substitution is deemed infeasible by ERCOT or the QSE informs ERCOT that the Ancillary Services capacity needs to be replaced, then ERCOT shall procure, if in its sole discretion it finds that the service is still needed, the Ancillary Services capacity required under Section 6.4.8.2.

(3) ERCOT shall charge each QSE that has failed according to paragraph (1) on its Ancillary Service Supply Responsibility for a particular Ancillary Service for a specific hour. The hourly charge of the failure is either (a) or (b):

(a) If a SASM is executed for that hour, then the charge equals the MW amount of the failed Ancillary Services Supply Responsibility multiplied by the greater of the:

(i) The MCPC for the Ancillary Service in the DAM for that hour ; or

(ii) The maximum MCPC set from any SASM for the same operating hour.

(b) If no SASM is executed for failure to supply for that hour, then the cost equals the MW amount of the failed Ancillary Services Supply Responsibility multiplied by the MCPC for the Ancillary Service in the DAM for that hour.

(4) If the Ancillary Service capacity of the affected QSE was awarded in the DAM or any SASM, then the QSE is still compensated for the quantity of the Ancillary Service capacity.

(5) If the Ancillary Service capacity of the affected QSE was not awarded in the DAM or any SASM (i.e., Self-Arranged Ancillary Service), then the QSE continues to receive credit toward its Ancillary Service Supply Responsibility.

6.4.8.2 Supplemental Ancillary Services Market

(1) During the Adjustment Period, ERCOT may procure additional Reg-Up, Reg-Down, Responsive Reserve, and Non-Spinning Services for the reasons, and in the amounts, specified in Section 6.4.8.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency, using a Supplemental Ancillary Services Market (SASM).

(2) The SASM process for acquiring more Ancillary Service capacity must use the following timeline with time "X" being the time that ERCOT sends notice to all QSEs of the SASM. Time X may be any time not less than two hours before the start of the Operating Hour for which the additional Ancillary Services capacity is required.

SASM Process	QSE Activities:	ERCOT Activities:

Time = X		Notify all QSEs of intent to procure additional Ancillary Services. Notify QSEs of any additional Ancillary Service Obligation, allocated to each LSE and aggregated to the QSE level.
Time = X plus 30 minutes	May submit additional quantity of Self-Arranged Ancillary Services limited to the additional Ancillary Services Obligation of the QSE.	Determine the amount of Ancillary Services to be procured.
Time = X plus 35 minutes		Execute SASM.
Time = X plus 45 minutes		Notify QSEs with awards of results Post the quantities and MCPCs of Ancillary Services bought in the SASM.
Time = X plus 60 minutes	Submit updated COP and updated Ancillary Service Schedule.	Validate COPs and Ancillary Service Schedules.

(3) Each QSE that is awarded capacity in a SASM is paid the SASM MCPC for the quantity it is awarded.

(4) ERCOT shall allocate additional Ancillary Service Obligations to QSEs using the same percentages as the original Day-Ahead allocation of Ancillary Service Obligations.

6.4.8.2.1 Resubmitting Offers for Ancillary Services in the Adjustment Period

(1) During the Adjustment Period, a QSE may resubmit an offer for an Ancillary Service that it submitted for a Resource, but was not struck in a previous market. The resubmitted offer for that Resource must meet the following criteria to be considered a valid offer in any subsequent market:

(a) The resubmitted offer quantity (in MW) must be offered at a price equal to or less than the lowest price of the previous offer for capacity of the portion that was not resubmitted;

(b) For any amount of the offer that is greater in quantity than the QSE's offer that was not selected in a previous market, the incremental amount of the offer may be submitted at any price subject to applicable offer caps and offer floors; and

(c) If ERCOT notifies Market Participants that additional Ancillary Services are needed, only offers that were submitted before the notice are eligible to participate in the SASM; once the notice is given, no further offers are eligible for that SASM.

6.4.8.2.2 SASM Clearing Process

SASM procurement requirements are:

(a) ERCOT shall procure the additional quantity required of each Ancillary Service, less the quantity self-arranged, if applicable. ERCOT may not buy more of one Ancillary Service in place of the quantity of a different service.

(b) ERCOT shall select Ancillary Service Offers submitted by QSEs, such that:

(i) For each Ancillary Service being procured, other than Reg-Down, ERCOT shall select offers that minimize the overall offer-based cost of these Ancillary Services. For each of these Ancillary Services, if selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(ii) For Reg-Down, ERCOT shall procure required quantities by selecting capacity in ascending order starting from the lowest-priced offer. ERCOT shall continue this selection process until the required quantity of Reg-Down is obtained. If selection of the Resource offer exceeds ERCOT's required Ancillary Service quantity, then ERCOT shall select a portion of the Resource offer to meet the Ancillary Service quantity required. For Load Resources offering a block of capacity, ERCOT shall ignore the offer unless the entire block can be accepted.

(c) If a QSE has submitted offers of the same Resource capacity for more than one Ancillary Service (sometimes called linked offers), ERCOT may not select any one part of that Resource capacity to provide more than one Ancillary Service in the same Operating Hour. ERCOT may, however, select part of that Resource capacity to provide one Ancillary Service and another part of that capacity to provide a different Ancillary Service in the same Operating Hour.

(d) The SASM MCPC for each hour for each service is the Shadow Price for the corresponding Ancillary Service constraint for the hour as determined by the SASM algorithm.

6.4.8.2.3 Communication of SASM Results

(1) As soon as practicable, but no later than the time specified in Section 6.4.8.2, Supplemental Ancillary Services Market, ERCOT shall notify each QSE of its awarded Ancillary Service Offer quantities in each SASM, specifying Resource, Ancillary Service type, SASM MCPC, and first and last hours of the awarded offer.

(2) As soon as practicable, but no later than the time specified in Section 6.4.8.2 ERCOT shall post on the MIS Public Area the hourly:

(a) SASM MCPC for each type of Ancillary Service for each hour;

(b) Total Ancillary Service procured in MW by Ancillary Service type for each hour; and

(c) Aggregated Ancillary Service Offer Curve for each Ancillary Service for each hour.

(3) ERCOT shall monitor SASM MCPCs for errors and shall "flag" for further review questionable prices before posting and make notations in the posting if there are conditions that cause the prices to be questionable.

6.5 Real-Time Energy Operations

6.5.1 ERCOT Activities

ERCOT activities during Real-Time operations are summarized in the table located in Section 6.3.2, Activities for Real-Time Operations. That table is intended to be only a general guide and not controlling language, and any conflict between the table and another section of the Protocols is controlled by the other section.

6.5.1.1 ERCOT Control Area Authority

ERCOT, as Control Area Operator (CAO), is authorized to perform the following actions for the limited purpose of securely operating the ERCOT Transmission Grid under the standards specified in North American Electric Reliability Corporation (NERC) Standards, the Operating Guides and these Protocols, including:

(a) Direct the physical operation of the ERCOT Transmission Grid, including circuit breakers, switches, voltage control equipment, and Load-shedding equipment;

(b) Dispatch Resources that have committed to provide Ancillary Services;

(c) Direct changes in the operation of voltage control equipment;

(d) Direct the implementation of Reliability Must-Run (RMR) Service, Remedial Action Plans (RAPs), Special Protection Systems (SPSs), and transmission switching to prevent the violation of ERCOT Transmission Grid security limits; and

(e) Perform additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT Transmission Grid to a secure state in the event of an ERCOT Transmission Grid Emergency Condition.

6.5.1.2 Centralized Dispatch

(1) ERCOT shall centrally Dispatch Resources and Transmission Facilities under these Protocols, including deploying energy by establishing Base Points, and Emergency Base Points, and by deploying Regulation Service, Responsive Reserve (RRS) service, and Non-Spinning Reserve (Non-Spin) service to ensure operational security.

(2) ERCOT shall verify that either an Energy Offer Curve providing prices for the Resource between its High Sustained Limit (HSL) and Low Sustained Limit (LSL) or an Output Schedule has been submitted for each On-Line Resource an hour before the end of the Adjustment Period for the upcoming Operating Hour. ERCOT shall notify Qualified Schedulingt Entities (QSEs) that have not submitted an Output Schedule or Energy Offer Curve through the Market Information System (MIS) Certified Area.

(3) ERCOT is the regional security coordinator for the ERCOT Region and is responsible for all regional security coordination as defined in the NERC Operating Manual and applicable ERCOT operating manuals or Operating Guides.

(4) ERCOT may only issue Dispatch Instructions for the Real-Time operation of Transmission Facilities to a Transmission Service Provider (TSP), for the Real-Time operation of distribution facilities to a Distribution Service Provider (DSP), or for a Resource to the QSE that represents it.

(5) ERCOT shall post shift schedules on the MIS Secure Area.

6.5.2 Operating Standards

ERCOT and each TSP shall operate the ERCOT Transmission Grid under these Protocols, and, to the extent they are not inconsistent with these Protocols, Good Utility Practice and NERC standards and policies. These Protocols control to the extent of any inconsistency between the Protocols and any of the following documents:

(a) The Operating Guides;

(b) The NERC standards and policies and the ERCOT procedures manual, supplied by NERC and ERCOT, respectively, as references for ERCOT Operators to use during normal and emergency operations of the ERCOT Transmission Grid;

(c) Specific operating procedures and RAPs submitted to ERCOT by individual Transmission Facilities owners or operators to address operating problems on their respective grids that could affect operation of the ERCOT Transmission Grid; and

(d) Guidelines established by the ERCOT Board, which may be more stringent than those established by NERC for the secure operation of the ERCOT Transmission Grid.

6.5.3 Equipment Operating Ratings and Limits

(1) ERCOT shall consider all equipment operating limits when issuing Dispatch Instructions. Except as stated in Section 6.5.9, Emergency Operations, if a Dispatch Instruction conflicts with a restriction that may be placed on equipment from time to time by a TSP, a DSP, or a Generation Resource's QSE to protect the integrity of equipment, ERCOT shall honor the restriction.

(2) Each TSP shall notify ERCOT of any limitations on the TSP's system that may affect ERCOT Dispatch Instructions. ERCOT shall continuously maintain a posting on the MIS Secure Area of any TSP limitations that may affect Dispatch Instructions. Examples of such limitations may include: temporary changes to transmission or transformer ratings, temporary changes to range of automatic tap position capabilities on auto-transformers, fixing or blocking tap changer, changes to no-load tap positions or other limitations affecting the delivery of energy across the ERCOT Transmission Grid. Any conflicts that cannot be satisfactorily resolved may be brought to ERCOT by any of the affected Entities for investigation and resolution.

6.5.4 Inadvertent Energy Account

ERCOT shall track any differences between the scheduled net interchange and the actual net interchange at each Direct Current Tie (DC Tie) in an "Inadvertent Energy Account" between ERCOT and each interconnected non-ERCOT Control Area. ERCOT shall coordinate operation of each DC Tie with the DC Tie Operator such that the Inadvertent Energy Account is maintained as close to zero as possible. Corrections of inadvertent energy between ERCOT and the other NERC-interconnected non-ERCOT Control Areas must comply with the NERC scheduling protocols and the ERCOT Operating Guides. ERCOT shall establish procedures to correct Inadvertent Energy Accounts with non-ERCOT Control Areas that are not subject to NERC scheduling protocols.

6.5.5 QSE Activities

QSE activities during Real-Time operations are summarized in the table located in Section 6.3.2, Activities for Real-Time Operations. That table is intended to be only a general guide and not controlling language, and any conflict between the table and another section of the Protocols is controlled by the other section.

6.5.5.1 Changes in Resource Status

(1) Each QSE shall notify ERCOT of a change in Resource Status via telemetry and through changes in the Current Operating Plan (COP) as soon as practicable following the change.

(2) Each QSE shall promptly inform ERCOT when the operating mode of its Generation Resource's Automatic Voltage Regulator (AVR) or Power System Stabilizer (PSS) is

changed while the Resource is On-Line. The QSE shall also provide the Resource's AVR or PSS status logs to ERCOT upon request.

(3) Each QSE shall immediately report to ERCOT and the TSP any inability of the QSE's Generation Resource required to meet its reactive capability requirements in these Protocols.

6.5.5.2 Operational Data Requirements

(1) ERCOT shall use Operating Period data to monitor and control the reliability of the ERCOT Transmission Grid and shall use it in network analysis software to predict the short-term reliability of the ERCOT Transmission Grid. Each TSP, at its own expense, may obtain that Operating Period data from ERCOT or directly from QSEs.

(2) A QSE representing a Generation Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time telemetry data to ERCOT for each Generation Resource. ERCOT shall make that data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to requesting TSPs and DSPs operating within ERCOT. Such data must be provided to the requesting TSP or DSP at the requesting TSP's or DSP's expense, including:

(a) Net real power (in MW) as measured by installed power metering or as calculated in accordance with ERCOT Operating Guides based on metered gross real power and conversion constants determined by the Resource Entity and provided to ERCOT as a result of Section 3.7, Resource Parameters. Net real power represents the actual generation of a Resource for all real power dispatch purposes, including use in Security-Constrained Economic Dispatch (SCED), determination of the High Ancillary Service Limit (HASL), High Dispatch Limit (HDL), Low Dispatch Limit (LDL) and Low Ancillary Service Limit (LASL), and is consistent with telemetered HSL and LSL;

(b) Gross real power (in MW) as measured by installed power metering or as calculated in accordance with ERCOT Operating Guides based on metered real power, which may include Supervisory Control and Data Acquisition (SCADA) metering, and conversions constants determined by the Resource entity and provided to ERCOT as a result of Section 3.7;

(c) Gross Reactive Power (in MVAr);

(d) Net Reactive Power (in MVAr);

(e) Power to standby transformers serving plant auxiliary Load;

(f) Status of switching devices in the plant switchyard not monitored by the TSP or DSP affecting flows on the ERCOT Transmission Grid;

(g) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(h) Generation Resource breaker and switch status;

(i) HSL;

(j) High Emergency Limit (HEL), under Section 6.5.9.2, Failure of the SCED Process;

(k) Low Emergency Limit (LEL), under Section 6.5.9.2;

(l) LSL;

(m) Ancillary Service Schedule for each quantity of Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), Responsive Reserve and Non-Spin:

(i) For Responsive Reserve and Non-Spin, the Ancillary Service Schedule is equal to the Ancillary Service Resource Responsibility minus the amount of Ancillary Service deployment;

(ii) For Regulation Service, the Ancillary Service Schedule is equal to the Ancillary Service Resource Responsibility;

(n) Ancillary Service Resource Responsibility for each quantity of Reg-Up, Reg-Down, Responsive Reserve and Non-Spin. The sum of Ancillary Service Resource Responsibility for all Resources in a QSE is equal to the Ancillary Service Supply Responsibility for that QSE; and

(o) Reg-Up and Reg-Down Services participation factors represent how a QSE is planning to deploy the Ancillary Service energy on a percentage basis to specific qualified Resource.

(3) For each wind-powered Generation Resource the QSE shall set the HSL to the output capability of the facility based upon all available units and the current measured wind speed (HSL must be equal to or greater than the latest telemetered net real power of the wind-powered Generation Resource).

(4) A QSE representing a Load Resource connected to Transmission Facilities or distribution facilities shall provide the following Real-Time data to ERCOT for each Load Resource and ERCOT shall make the data available, in accordance with ERCOT Protocols, NERC standards and policies, and Governmental Authority requirements, to the Load Resource's host TSP or DSP at the TSP or DSP expense. The net real power consumption, Low Power Consumption (LPC) and Maximum Power Consumption (MPC) shall be telemetered to ERCOT using a negative (-) sign convention:

(a) Net real power consumption (in MW);

(b) Any data mutually agreed to by ERCOT and the QSE to adequately manage system reliability;

(c) Load Resource breaker status;

(d) LPC;

(e) MPC;

(f) Ancillary Service Schedule for each quantity of Reg-Up, Reg-Down, Responsive Reserve and Non-Spin;

(g) Ancillary Service Resource Responsibility for each quantity of Reg-Up, Reg-Down, Responsive Reserve and Non-Spin;

(h) The status of the high-set under-frequency relay, if required for qualification;

(i) For a Controllable Load Resource, the Scheduled Power Consumption that represents zero Ancillary Service deployments; and

(j) For a Controllable Load Resource, Net Reactive Power (in MVAr).

(5) A QSE with Resources used in SCED shall provide communications equipment to receive ERCOT-telemetered control deployments.

(6) A QSE providing any Regulation Service shall provide telemetry indicating the appropriate status of Resources providing Reg-Up or Reg-Down, including status indicating whether the Resource is temporarily blocked from receiving Reg-Up and/or Reg-Down deployments from the QSE.

(7) Real-Time data for reliability purposes must be accurate to within three percent. This telemetry may be provided from relaying accuracy instrumentation transformers.

(8) Each QSE shall report the current configuration of combined-cycle Resources that it represents to ERCOT.

(a) Each configuration for a power block of combined-cycle Resources is considered as a single Resource unless multiple generators are connected to the ERCOT Transmission Grid at different voltage levels.

(b) Each QSE shall use continuous telemetry to report changes to Combined-Cycle Configurations. Changes must be reported by changing the Resource Status in Real-Time and in the COP for that Resource representing the desired Combined-Cycle Configuration. Each QSE shall provide ERCOT with the elements comprising each Combined-Cycle Configuration for a Resource through Real-Time telemetry and by appropriate entries in the COP.

(c) Each QSE shall provide individual telemetered generator output (MW and MVAr) and Resource Status that indicates the Combined-Cycle Configuration to be used in SCED and Reliability Unit Commitment (RUC).

(9) A QSE representing combined-cycle Resources shall provide ERCOT with the possible operating configurations for each power block with accompanying limits and price points. Power augmentation methods must be made available to ERCOT as part of one or more of the configurations. Price points for the range of the curve represented by the power augmentation method must reflect the price of the added capability. Such power augmentation methods may include:

(a) Combustion turbine inlet air cooling (CTIAC) methods;

(b) Duct firing;

(c) Other ways of temporarily increasing the output of combined-cycle Resources; and

(d) For Qualifying Facilities (QFs), an LSL that represents the minimum energy available, in MW, from the Resource for economic dispatch based on the minimum stable steam delivery to the thermal host plus a justifiable reliability margin that accounts for changes in ambient conditions.

6.5.6 TSP and DSP Responsibilities

(1) Each TSP shall notify ERCOT of any changes in status of Transmission Elements as provided in these Protocols and clarified in the ERCOT procedures.

(2) Each TSP shall as soon as practicable report to ERCOT any short-term inability to meet minimum TSP reactive requirements.

(3) Each DSP shall as soon as practicable report to ERCOT any short-term inability to meet minimum DSP reactive requirements.

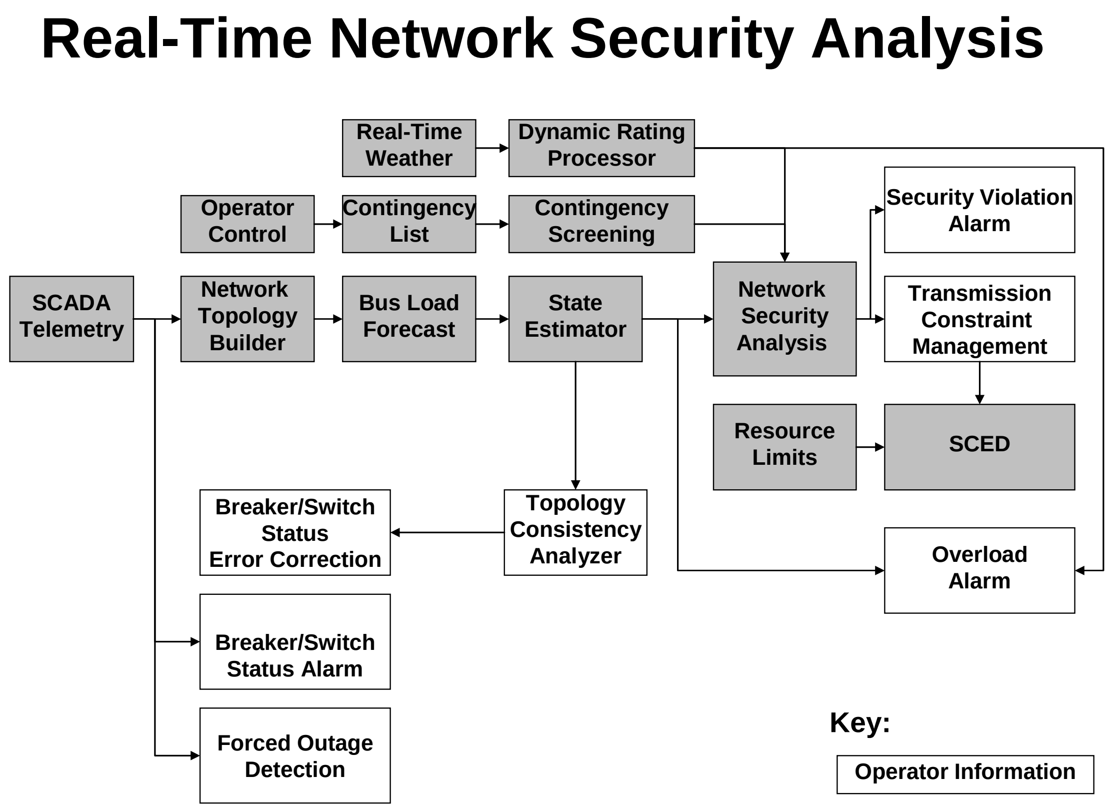
6.5.7 Energy Dispatch Methodology

This Section outlines the programmatic and manual processes employed by ERCOT to simultaneously achieve power balance (minimizing the use of Regulation Service) and manage congestion while operating within the constraints of the system at economically optimized cost. The Real-Time Sequence describes the key system components and inputs that are required to support the SCED process, which produces the Locational Marginal Prices (LMPs) and Base Points while meeting transmission system constraints. Section 6.5.7.3, Security Constrained Economic Dispatch, provides further details regarding additional components and inputs and ex-ante mitigation.

6.5.7.1 Real-Time Sequence

(1) The Real-Time Sequence consists of multiple interdependent processes that are driven by telemetry data and the network topology. This section describes the core aspects of the Real-Time Sequence.

(2) The figure below highlights the key computational modules and processes that are used during the Real-Time Sequence:



6.5.7.1.1 SCADA Telemetry

SCADA telemetry provides the actual Real-Time status and output of Resources and the status of observable Transmission Elements of the Network Operations Model.

6.5.7.1.2 Network Topology Builder

The Network Topology Builder creates the Updated Network Model based on the observed topology of the ERCOT Transmission Grid. The Updated Network Model is then used as the basis for the State Estimator solution.

6.5.7.1.3 Bus Load Forecast

Once the Updated Network Model is created, the transmission Electrical Buses in the model will have a Bus Load Forecast applied. The forecasted Load must be denoted with a low State Estimator measurement confidence factor. The State Estimator must use the forecasted Load coupled with the remaining telemetry of line flows and voltages to estimate the actual Load on each Electrical Bus.

6.5.7.1.4 State Estimator

The State Estimator must use the Bus Load Forecast and the remaining telemetry information of line flows and voltages to estimate all the transmission parameters needed to provide, on convergence, a mathematically consistent data set of constrained inputs to the Network Security Analysis (NSA) and the Topology Consistency Analyzer.

6.5.7.1.5 Topology Consistency Analyzer

The Topology Consistency Analyzer identifies possibly erroneous breaker and switch status. The Topology Consistency Analyzer must notify ERCOT of inconsistencies detected and must indicate the correct breaker and switch status(es) when the preponderance of redundant information from the telemetered database indicates true errors in status. For example, such processing would detect flow on lines, flow on devices or network load, shown as disconnected from the transmission system and would indicate to ERCOT that there was a continuity error associated with the flow measurement or status indication. ERCOT may override SCADA telemetry as required to correct erroneous breaker and switch status before that information is processed by the NSA for the next SCED interval. ERCOT shall notify the TSP or QSE, who shall correct the status indications as soon as practicable. The Topology Consistency Analyzer maintains a summary of all incorrect status indicators and provides that information to all TSPs and other Market Participants through the MIS Secure Area.

6.5.7.1.6 Breakers/Switch Status Alarm Processor and Forced Outage Detection Processor

The Real-Time Sequence includes processes that detect and provide alarms to the ERCOT Operator when the status of breakers and switches, Resources, transmission lines and transformers, and Load disconnected from the Updated Network Model changes. Also, the ERCOT Operator must be able to determine if an Outage of Transmission Facilities had been scheduled in the Outage Scheduler or is a Forced Outage.

6.5.7.1.7 Real-Time Weather and Dynamic Rating Processor

(1) The Dynamic Rating Processor provides Dynamic Ratings using the processes described in Section 3.10.8, Dynamic Ratings, for all transmission lines and transformer elements with Dynamic Ratings designated by the TSPs. ERCOT shall obtain Real-Time weather

data, where available, from multiple locations and provide it to the Dynamic Rating Processor. Weather conditions must include ambient temperature and may include wind speed when available. ERCOT shall post summaries of dynamically adjusted Transmission Element limits on the MIS Secure Area in a form that allows Market Participants to directly upload Real-Time data into the Common Information Model (CIM).

(2) On a monthly basis, ERCOT shall provide a summary report for each dynamically rated Transmission Element specifying the average change in Normal Rating in MVA that is gained on the element through use of a Dynamic Rating rather than the Normal Rating. ERCOT shall post this report to the MIS Secure Area.

6.5.7.1.8 Overload Alarm Processor

Once transmission line and transformer Dynamic Ratings are retrieved, ERCOT shall compare the actual flow and state estimated flow calculation of MVA to the effective Transmission Element limit and, if an out-of-limit condition exists, ERCOT shall produce an overload notification.

6.5.7.1.9 Contingency List and Contingency Screening

For the Real-Time Sequence, ERCOT may select relevant contingencies from a standard contingency list previously developed by ERCOT under Section 5.5.1, Security Sequence, that are likely to be active in Real-Time. ERCOT may use the information provided by the Hour-Ahead or Day-Ahead NSA to assist in determining which contingencies are candidates for activation.

6.5.7.1.10 Network Security Analysis Processor and Security Violation Alarm

(1) Using the input provided by the State Estimator, ERCOT shall use the NSA processor to perform analysis of all contingencies remaining in the active list. For each contingency, ERCOT shall use the NSA processor to monitor the elements for limit violations. ERCOT shall use the NSA processor to verify Electrical Bus voltage limits to be within a percentage tolerance as outlined in the ERCOT Operating Guides. Contingency security violations for transmission lines and transformers occur if:

(a) The predicted post-contingency MVA exceeds 100% of the Emergency Rating after adjustments for Real-Time weather conditions applicable to the contingency are incorporated; and

(b) A RAP or SPS is not defined allowing relief within the time allowed by the security criteria.

(2) When the NSA processor notifies ERCOT of a security violation, ERCOT shall immediately initiate the process described in Section 6.5.7.1.11, Transmission Constraint Management.

(3) If the SCED does not resolve an insecure state, ERCOT shall attempt to relieve the insecure state by:

(a) Confirming that pre-determined relevant RAPs are properly modeled in the system;

(b) Re-dispatching generation through the mechanism of over-riding HDLs and LDLs to provide more capacity to SCED;

(c) After declaring an Alert, as appropriate, manual Dispatch of generation;

(d) Removing non-cascading contingency overload/constraints from the SCED process; and

(e) If all other mechanisms have failed, ERCOT may authorize the use of a Mitigation Action Plan (MAP) previously reviewed by the appropriate TSP or DSP. A MAP is a set of pre-defined actions taken beyond normal RAPs under emergency circumstances to relieve transmission security violations.

(3) NSA must be capable of analyzing contingencies, including the effects of automatically deployed SPSs and RAPs. The NSA must fully integrate into the evaluation and deployment of these SPSs and RAPs and notify the ERCOT Operator of the application of these SPSs and RAPs to the solution.

(4) The Real-Time NSA may employ the use of appropriate ranking and other screening techniques to further reduce computation time by executing one or two iterations of the contingency study to gauge its impact and discard further study if the estimated result is inconsequential.

6.5.7.1.11 Transmission Constraint Management

(1) ERCOT may not allow any contingency anticipated to be active in SCED, identified by NSA, until it has verified that the contingency is accurate and appropriate given the current operating state of the ERCOT Transmission Grid. ERCOT shall continuously post to the MIS Secure Area any active contingencies in SCED and any contingencies that it has determined to be inaccurate or inappropriate and thus excluded from SCED under Section 5.5.1, Security Sequence. The ERCOT System Operator will flag for further review by ERCOT any contingencies deemed inaccurate or inappropriate.

(2) ERCOT shall establish a maximum Shadow Price for each constraint as part of the definition of contingencies. The cost calculated by SCED to resolve an additional MW of congestion on the constraint is limited to the maximum Shadow Price for the

constraint. ERCOT shall develop a policy for setting maximum Shadow Prices for approval through the Protocol Revision Request (PRR) process.

(3) When ERCOT identifies a binding constraint on a repeated basis ERCOT shall have procedures established to contact the appropriate TSP and validate the accuracy of the Network Operations Model according to paragraph (5) of Section 3.10.4, ERCOT Responsibilities.

(4) If ERCOT determines that rating(s) in the Network Operations Model or configuration of the Transmission Facilities are not correct, then the TSP will provide the appropriate data submittals to ERCOT to correct the problem upon notification by ERCOT.

6.5.7.1.12 Resource Limits

(1) The following Generation Resource limits are calculated by ERCOT and used as inputs by the SCED process:

(a) HASL;

(b) LASL;

(c) Normal Ramp Rate by using the curve submitted by the QSE and the Resource's MW telemetry;

(d) Emergency Ramp Rate by using the curve submitted by the QSE and the Resource's MW telemetry;

(e) SCED Up Ramp Rate (SURAMP), which represents the ability of a Generation Resource to increase generation output in SCED.

(f) SCED Down Ramp Rate (SDRAMP), which represents the ability of a Generation Resource to decrease generation output in SCED.

(g) HDL, which represents a dynamically calculated MW upper limit on a Resource that describes the maximum capability of the Resource SCED dispatch for the next five minutes (the Resource's Real-Time generation plus the product of the Normal Ramp Rate at that Real-Time output level multiplied by five), restricted by HASL;

(h) LDL, which represents a dynamically calculated MW lower limit on a Resource that describes the minimum capability of the Resource SCED dispatch for the next five minutes (the Resource's Real-Time generation minus the product of the Normal Ramp Rate at that Real-Time output level multiplied by five), restricted by LASL.

(2) The following Load Resource limits are calculated by ERCOT and used in other calculations and as information for ERCOT Operators:

(a) HASL; and

(b) LASL.

(3) For a more detailed explanation of all the Resource limits calculated by ERCOT, please reference Section 6.5.7.2, Resource Limit Calculator.

6.5.7.1.13 Data Inputs and Outputs for the Real-Time Sequence and SCED

(1) Inputs: The following information must be provided as inputs to the Real-Time Sequence and SCED. ERCOT may require additional information as required, including:

(a) Real-Time data from TSPs including status indication for each point if that data element is stale for more than 20 seconds;

(i) Transmission Electrical Bus voltages;

(ii) MW and Mvar pairs and calculated MVA for all lines and transformers and reactors;

(iii) Actual breaker and switch status for all modeled devices;

(iv) Tap position for auto-transformers.

(b) State Estimator results (MW and Mvar pairs and calculated MVA)for all modeled Transmission Elements;

(c) Logic equations to determine the in- or out-of-service state of a transmission line or transformer;

(d) Transmission Element ratings from TSPs;

(i) Data from the CIM:

(A) Transmission lines – Normal and Emergency Ratings (MVA); and

(B) Transformers and Auto-transformers – Normal and Emergency Ratings (MVA) and tap position limits.

(ii) Data from QSEs:

(A) Generator Step-up transformers tap position;

(B) Resource HSL (from telemetry); and

(C) Resource LSL (from telemetry).

(e) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

(2) ERCOT shall validate the inputs of the Resource Limit Calculator as follows:

(a) The calculated SCED Up Ramp Rate and SCED Down Ramp Rate are each greater than or equal to zero; and

(b) Other provision specified under Section 3.18, Resource Limits in Providing Ancillary Service.

(3) Outputs for ERCOT Operator information and possible action include:

(a) Operator notification of any change in status of any breaker or switch;

(b) Lists of all breakers and switches not in their normal position;

(c) Result of logic equation calculation of the in and out status of transmission lines and transformers;

(d) Operator notification of all Transmission Element overloads detected from telemetered or State-Estimated data;

(e) Operator notification of all Transmission Element security violations; and

(f) Operator summary displays

(i) Transmission system status changes;

(ii) Overloads;

(iii) System security violations; and

(iv) Base Points.

(4) Every hour, ERCOT shall post on the MIS Secure Area the following information:

(a) Status of all breakers and switches used in the NSA except breakers and switches connecting Resources to the ERCOT Transmission Grid;

(b) Transmission flows and voltages from the State Estimator;

(c) Individual transmission Load on Electrical Buses, sum of the Load on each Electrical Bus in each Load Zone, and total Load on Electrical Buses in the ERCOT System, the sum of ERCOT generation, and flow on the DC Ties, all from the State Estimator;

(d) Transformer flows, voltages and tap position from the State Estimator;

(e) All binding transmission constraints and the contingency or overloaded element pairs that caused such constraint;

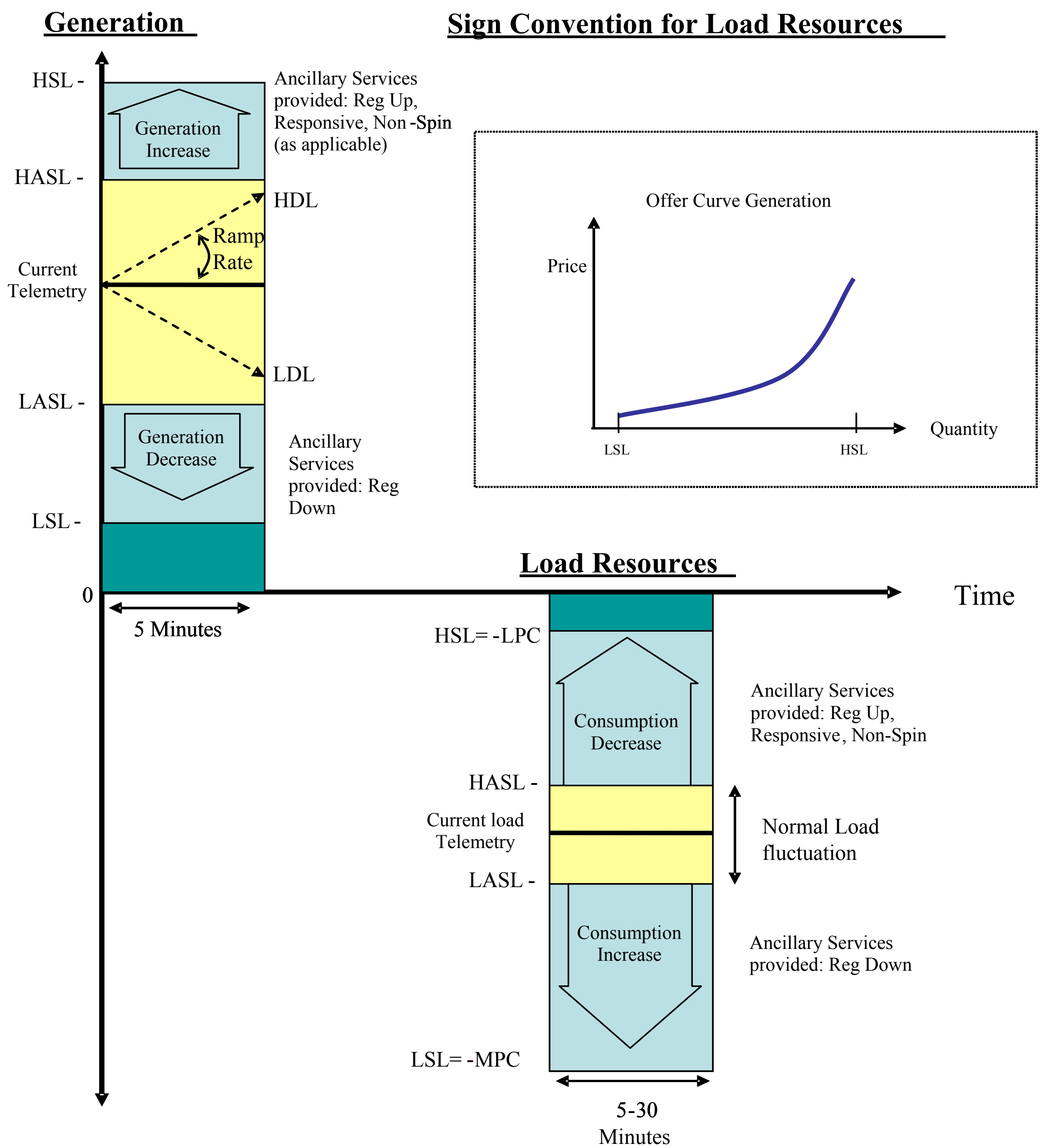
(f) All Shadow Prices on binding transmission constraints; and

(g) The 15-minute average of Loads on the Electrical Buses from State Estimator results.

6.5.7.2 Resource Limit Calculator

(1) ERCOT shall calculate the HASL, LASL, SCED up ramp rate (SURAMP), SCED down ramp rate (SDRAMP), HDL and LDL within four seconds after a change of the Resource-specific attributes provided as part of the QSE's SCADA telemetry under Section 6.5.5.2, Operational Data Requirements. The formulas described below define which Resource-specific attributes must be used to calculate each Resource limit. The Resource limits are used as inputs into both the SCED process and the Ancillary Service Capacity Monitor as described in Section 6.5.7.6, Load Frequency Control. These Resource limits help ensure that the deployments produced by the SCED and Load Frequency Control (LFC) processes will respect the commitment of a Resource to provide Ancillary Services as well as individual Resource physical limitations.

(2) The figure below illustrates how the Resource Limit Calculator determines the Resource limits for both Generation and Load Resources:


Generation
Sign Convention for Load Resources
HSL -
Generation Increase
Ancillary Services provided: Reg Up, Responsive, Non-Spin (as applicable)
HASL -
HDL
Ramp Rate
Current Telemetry
LDL
LASL -
Generation Decrease
Ancillary Services provided: Reg Down
LSL -
0
5 Minutes
Offer Curve Generation
Price
Quantity
LSL
HSL
Load Resources
Time
HSL= -LPC
Consumption Decrease
Ancillary Services provided: Reg Up, Responsive, Non-Spin
HASL -
Current load Telemetry
Normal Load fluctuation
LASL -
Consumption Increase
Ancillary Services provided: Reg Down
LSL= -MPC
5-30 Minutes

(3) HASL is calculated as follows:

HASL = Max (LASL, (HSLTELEM – (RRSTELEM + RUSTELEM + NSRSTELEM)))

Variable	**Description**
HASL	High Ancillary Service Limit
HSLTELEM	High Sustained Limit provided via telemetry – per Section 6.5.5.2
LASL	Low Ancillary Service Limit
RRSTELEM	Responsive Reserve Ancillary Service Schedule provided by telemetry
RUSTELEM	Reg-Up Ancillary Service Resource Responsibility designation provided by telemetry
NSRSTELEM	Non-Spin Ancillary Service Schedule provided via telemetry

(4) LASL is calculated as follows:

LASL = LSLTELEM + RDSTELEM

Variable	**Description**
LASL	Low Ancillary Service Limit
LSLTELEM	Low Sustained Limit provided via telemetry
RDSTELEM	Reg-Down designation provided by telemetry

(5) For each Generation Resource, the SURAMP is calculated as follows:

SURAMP = RAMPRATE – (RUSTELEM / 5)

Variable	**Description**
SURAMP	SCED up ramp rate
RAMPRATE	Normal Ramp Rate when RRS is not deployed or when the subject Resource is not providing RRS. Emergency Ramp Rate for Resources deploying RRS
RUSTELEM	Reg-Up designation provided by telemetry

(6) For each Generation Resource, the SDRAMP is calculated as follows:

SDRAMP = NORMRAMP – (RDSTELEM / 5)

Variable	**Description**
SDRAMP	SCED down ramp rate
NORMRAMP	Normal Ramp Rate
RDSTELEM	Reg-Down designation by Resource provided via telemetry

(7) For Generation Resources, HDL is calculated as follows:

HDL = Min (POWERTELEM + (SURAMP * 5), HASL)

Variable	Description
HDL	High Dispatch Limit
POWERTELEM	Gross or net real power provided via telemetry
SURAMP	SCED up ramp rate
HASL	High Ancillary Service Limit – definition provided in Section 2, Definitions and Acronyms.

(8) For Generation Resources, LDL is calculated as follows:

LDL = Min {Max (POWERTELEM - (SDRAMP * 5), LASL), HSL}

Variable	Description
LDL	Low Dispatch Limit
POWERTELEM	Gross or net real power provided via telemetry
SDRAMP	SCED down ramp rate
HSL	High Sustained Limit
LASL	Low Ancillary Service Limit – definition provided in Section 2.

6.5.7.3 Security Constrained Economic Dispatch

(1) The SCED process is designed to simultaneously manage energy balance and congestion through Resource Base Points and calculation of LMPs every five minutes. The SCED process uses a two-step methodology that applies mitigation prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves and Output Schedules to produce a least cost dispatch of On-Line Generation Resources to the total current generation requirement determined by LFC, subject to transmission constraints. The SCED process uses the Resource Status provided by SCADA Telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP.

(2) The SCED solution must monitor cumulative deployment of Regulation Services and ensure that Regulation Services deployment is minimized over time.

(3) For use as SCED inputs, ERCOT shall use the available capacity of all committed Generation Resources by creating proxy Energy Offer Curves for certain Resources as follows:

(a) Non-wind-powered Generation and Dynamically Scheduled Resources without Energy Offer Curves.

ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below for:

(i) Each non-wind-powered Generation Resource for which its QSE has submitted an Output Schedule instead of an Energy Offer Curve; and

(ii) Each Dynamically Scheduled Resource that has not submitted Incremental and Decremental Energy Offer Curves.

MW	**Price (per MWh)**
HSL	SWCAP
Output Schedule MW plus 1 MW	SWCAP minus $0.01
Output Schedule MW	-$249.99
LSL	-$250.00

(b) Dynamically Scheduled Resources with Energy Offer Curves

For each Dynamically Scheduled Resource that has submitted Incremental and Decremental Energy Offer Curves, ERCOT shall create a monotonically increasing proxy Energy Offer Curve. That curve must consist of the Incremental Energy Offer Curve that reflects the available capacity above the Resource's Output Schedule to its HSL and the Decremental Energy Offer Curve that reflects the available capacity below the Resource's Output Schedule to the LSL. The curve must be created as described below:

MW	**Price (per MWh)**
Output Schedule MW plus 1 MW to HSL	Incremental Energy Offer Curve
LSL to Output Schedule MW	Decremental Energy Offer Curve

(c) Non-wind-powered Generation Resources without full-range Energy Offer Curves

For each non-wind-powered Generation Resource for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the Resource's available capacity, ERCOT shall create a proxy Energy Offer Curve that extends the submitted Energy Offer Curve to use the entire available capacity of the Resource using the System-Wide Offer Cap above the highest point on the Energy Offer Curve to the Resource's HSL and the offer floor from the lowest point on the Energy Offer Curve to its LSL, using these points:

MW	**Price (per MWh)**
HSL (if more than highest MW in Energy Offer Curve)	SWCAP
1 MW above highest MW in Energy Offer Curve (if less than HSL)	SWCAP minus $0.01
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-$249.99
LSL (if less than lowest MW in Energy	-$250.00

Offer Curve)	

(d) Wind-powered Generation Resource

(i) For each wind-powered Resource that has not submitted an Energy Offer Curve ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	**Price (per MWh)**
HSL	SWCAP
HSL minus 1 MW	-$249.99
LSL	-$250.00

(ii) For each wind-powered Resource for which its QSE has submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	**Price (per MWh)**
HSL (if more than highest MW in Energy Offer Curve)	SWCAP
1 MW above highest MW in Energy Offer Curve (if less than HSL)	SWCAP minus $0.01
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-$250.00

(4) The creation of a proxy Energy Offer Curve by ERCOT under this Section does not constitute the submission of an offer by a QSE for purposes of paragraph (2) of Section 1.3.3, Expiration of Confidentiality.

(5) The two-step SCED methodology referenced in paragraph (1) above is:

(a) The first step is to execute the SCED process to determine Reference LMPs. In this step ERCOT executes SCED using the full Network Operations Model while only observing limits of Competitive Constraints. Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT under this section are used in the SCED to determine "Reference LMPs."

(b) The second step is to execute the SCED process to produce Base Points, Shadow Prices, and LMPs, subject to security constraints (including Competitive and Non-Competitive Constraints) and other Resource constraints. The second step must:

(i) Use Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT. Each Energy Offer Curve must be capped at the greater of the Reference LMP (from Step 1) at the

Resource Node or the appropriate Mitigated Offer Cap and bounded at the lesser of the Reference LMP (from Step 1) at the Resource Node or the appropriate Mitigated Offer Floor; and

(ii) Observe all Competitive and Non-Competitive Constraints.

(c) ERCOT shall archive information and provide monthly summaries of security violations and any binding transmission constraints identified in Step 2 of the SCED process. The summary must describe the Limiting Element (or identified operator-entered constraint with operator's comments describing the reason and the Resource-specific impacts for any manual overrides). ERCOT shall provide the summary to Market Participants on the MIS Secure Area and to the Independent Market Monitor (IMM).

6.5.7.4 Base Points

ERCOT shall issue a Base Point for each On-Line Generation Resource on completion of each SCED execution. The Base Point set by SCED must observe a Generation Resource's HDL and LDL. Base Points are automatically superseded on receipt of a new Base Point from ERCOT regardless of the status of any current ramping activity of a Resource. ERCOT shall provide each Base Point using Dispatch Instructions issued over Inter-Control Center Protocol (ICCP) data link to the QSE representing each Resource that include the following information:

(a) Resource identifier that is the subject of the Dispatch Instruction;

(b) MW output;

(c) Time of the Dispatch Instruction; and

(d) Other information relevant to that Dispatch Instruction.

6.5.7.5 Ancillary Services Capacity Monitor

(1) ERCOT shall calculate the following every ten seconds and provide Real-Time summaries to ERCOT Operators and all Market Participants using the MIS Secure Area and ICCP, giving updates of calculations every ten seconds, which show the Real-Time total system amount of:

(a) Responsive Reserve Capacity from Generation Resources;

(b) Responsive Reserve Capacity from Load Resources excluding Controllable Load Resources;

(c) Responsive Reserve Capacity from Controllable Load Resources;

(d) Non-Spinning Reserve available from On-Line Generation Resources with Energy Offer Curves;

(e) Non-Spinning Reserve available from undeployed Load Resources;

(f) Non-Spinning Reserve available from Off-Line Generation Resources;

(g) Non-Spinning Reserve available from Resources with Output Schedules;

(h) Undeployed Reg-Up and undeployed Reg-Down;

(i) Available capacity with Energy Offer Curves in the ERCOT System that can be used to increase Base Points in SCED;

(j) Available capacity with Energy Offer Curves in the ERCOT System that can be used to decrease Base Points in SCED;

(k) Available capacity without Energy Offer Curves in the ERCOT System that can be used to increase Base Points in SCED; and

(l) Available capacity without Energy Offer Curves in the ERCOT System that can be used to decrease Base Points in SCED; and.

(m) The ERCOT-wide Physical Responsive Capability (PRC) calculated as follows:

$$\mathbf{PRC_1} = \sum_{i=\text{online generation resource}}^{\text{All online generation resources}} \mathbf{Min(Max((RDF*HSL - Actual\ Net\ Telemetered\ Output)_i\ ,\ 0.0)\ ,\ 0.2*RDF*HSL_i)}$$

$$\mathbf{PRC_2} = \sum_{i=\text{online generation resource}}^{\text{All online generation resources}} \text{((Hydro-synchronous condenser output)}_i \text{ as qualified by Operating Guide Section 2.5.2.3, Types of Responsive Reserve))}$$

PRC = PRC$_1$ + PRC$_2$

The above variables are defined as follows:

Variable	Unit	Description
PRC_1	MW	**Generation On-line greater than 0 MW**
PRC_2	**MW**	**Hydro-synchronous condenser output**
PRC	MW	**Physical Responsive Capability**
RDF		**The currently approved Reserve Discount Factor**

(2) Each QSE shall operate Resources providing Ancillary Service capacity to meet its obligations. If a QSE experiences temporary conditions where its total obligation for providing Ancillary Service can not be met on the QSE's Resources, then the QSE may add additional capability from other Resources that it represents. It adds that capability by changing the Resource Status and updating the Ancillary Service Schedules and Ancillary Services Resource Responsibility of the affected Resources and notifying ERCOT under Section 6.4.8.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency. If the QSE is unable to meet its total obligations to provide committed Ancillary Services capacity, the QSE shall notify ERCOT immediately of the expected duration of the QSE's inability to meet its obligations. ERCOT shall determine whether replacement Ancillary Services will be procured on behalf of the affected QSE according to Section 6.4.8.1.

6.5.7.6 Load Frequency Control

The function of LFC is to maintain system frequency without a cost optimization function. ERCOT shall execute LFC every four seconds to reduce system frequency deviations from scheduled frequency by providing a control signal to each QSE that represents Resources providing Regulation Service and RRS service.

6.5.7.6.1 LFC Process Description

(1) The LFC system corrects system frequency based on the Area Control Error (ACE) algorithm and Good Utility Practice.

(2) The ACE algorithm subtracts the actual frequency in Hz from the scheduled system frequency (normally 60Hz), and multiplies the result by the frequency bias constant of MW/0.1 Hz. The ACE algorithm then takes that product and subtracts the difference between the Real-Time output and the Base Point for all Dynamically Scheduled Resources. This calculation produces an ACE value, which is a MW-equivalent correction needed to control the actual system frequency to the scheduled system frequency value. ERCOT shall develop a methodology, subject to Technical Advisory Committee (TAC) approval, to determine the optimal frequency bias for given system conditions.

(3) The LFC module receives inputs from Real-Time telemetry that includes Resource output and actual system frequency. The LFC uses actual Resource information calculated from SCADA to determine available Resource capacity providing Regulation and RRS services.

(4) Based on the ACE MW correction, the LFC issues a set of control signals every four seconds to each QSE providing Regulation and, if required, each QSE providing Responsive Reserve. Control must be proportional to the QSE's share of each of the services that it is providing, respecting the QSE's Resources' capability to provide regulation control in each four-second interval. Control signals are provided to the QSE using the ICCP data link. QSEs shall receive an Updated Desired Base Point updated every four seconds by LFC.

(5) Each QSE shall allocate its Regulation energy deployment among its Resources to meet a deployment signal, and shall provide ERCOT with the participation factor of each Resource via telemetry in accordance with Section 6.5.7.6.2.1, Deployment of Regulation Service, and Section 6.4.8.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency. Each QSE's allocation of Regulation Service to its Resources must be consistent with the telemetry provided under Section 6.5.5.2, Operational Data Requirements. Each QSE's allocation of its Regulation energy deployment among its Resources to meet a deployment signal must ensure the participation factors of all its Generation Resources in comparison to all its Controllable Load Resources remains constant.

(6) If all Reg-Up capacity has been deployed, ERCOT shall use the LFC system to deploy Responsive Reserve on Generation Resources and Controllable Load Resources. Such Responsive Reserve deployments by ERCOT must be deployed as specified in Section 6.5.7.6.2.2, Deployment of Responsive Reserve Service.

(7) ERCOT shall settle energy that results from LFC deployment at the Settlement Point Price for the point of injection. When a QSE deploys Responsive Reserve Service, the QSE shall deploy units consistent with the performance criteria for RRS service in Sections 8.1.2.3.2, Responsive Reserve Service Capacity Monitoring Criteria and 8.1.2.4.2, Responsive Reserve Service Energy Deployment Criteria.

(8) The inputs for LFC include:

(a) Actual system frequency;

(b) Scheduled system frequency;

(c) Capacity available for Regulation by QSE;

(d) Telemetered high and low regulation availability status indications for each Resource available for Regulation deployments for ERCOT information;

(e) Resource limits calculated by ERCOT as described Section 6.5.7.2, Resource Limit Calculator;

(f) Resource Regulation participation factor;

(g) Capacity available for Responsive Reserve by QSE;

(h) ERCOT System frequency bias;

(i) Dynamically Scheduled Resource Base Points; and

(j) Telemetered Resource output.

(9) If system frequency deviation is greater than an established threshold, ERCOT may issue Dispatch Instructions to those Resources not providing Reg-Up or Reg-Down that have Base Points directionally opposite ACE, to temporarily suspend ramping to their Base Point until frequency deviation returns to zero.

6.5.7.6.2 LFC Deployment

ERCOT may deploy Regulation, Responsive Reserve, and Non-Spin only as prescribed by their respective specific functions to maintain frequency and system security. ERCOT may not substitute one Ancillary Service for another.

6.5.7.6.2.1 Deployment of Regulation Service

(1) ERCOT shall deploy Reg-Up and Reg-Down necessary to maintain ERCOT System frequency to meet NERC Control Area and other Control Area performance criteria as specified in these Protocols and the Operating Guides.

(2) Reg-Up is a deployment or recall of a deployment referenced to the Resource's Base Point in response to a change (up or down) in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

(3) Reg-Down is a deployment or recall of a deployment referenced to the Resource's Base Point in response to a change (up or down) in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

(4) These requirements also apply to the deployment or recall of a deployment of Reg-Up and Reg-Down:

(a) Deployment or recall of a deployment must be accomplished through use of an automatic signal from ERCOT to each QSE provider of Reg-Up and Reg-Down.

(b) ERCOT shall minimize Reg-Up and Reg-Down energy as much as practicable in each SCED cycle.

(c) ERCOT shall settle energy provided by Reg-Up and Reg-Down at the Resource's Settlement Point Price.

(d) ERCOT shall integrate the control signal sent to providers of Reg-Up and shall calculate the amount of energy deployed by Reg-Up in each Settlement Interval.

(e) ERCOT shall integrate the control signal sent to providers of Reg-Down and shall calculate the amount of energy deployed by Reg-Down in each Settlement Interval.

(f) ERCOT shall calculate for each LFC cycle the amount of regulation that each Resource is expected to provide at that instant in time. The expected amount must be averaged over each SCED interval. The actual generation from telemetry must also be averaged over each SCED interval.

(5) Every day, ERCOT shall post to the MIS Secure Area the total amount of deployed Reg-Up and Reg-Down energy in each Settlement Interval of the previous day.

(6) For each Resource providing Reg-Up or Reg-Down, the implied ramp rate in MW per minute is the total amount of Regulation Service awarded divided by five.

(7) Each QSE providing Reg-Up or Reg-Down and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring and Compliance.

(8) ERCOT shall issue Reg-Up and Reg-Down deployment Dispatch Instructions over ICCP. Those Dispatch Instructions must contain the change in MW output requested of the QSE assuming all Resources are at their last Base Point issued by SCED.

6.5.7.6.2.2 Deployment of Responsive Reserve Service

(1) Responsive Reserve is intended to:

(a) Help restore the frequency within the first few seconds of a significant frequency deviation of the interconnected transmission system;

(b) Provide energy during the implementation of an Emergency Electric Curtailment Plan (EECP); and

(c) Provide backup Reg-Up.

(2) ERCOT shall deploy RRS to meet NERC Control Area performance standards and other Control Area performance criteria as specified in these Protocols and the Operating Guides, by one or more of the following:

(a) Automatic generator governor action as a result of a significant frequency deviation;

(b) Through use of an automatic Dispatch Instruction signal to deploy Responsive Reserve from Generation Resources or Controllable Load Resources;

(c) By Dispatch Instructions for deployment of Responsive Reserve Energy from a Load Resource, excluding Controllable Load Resources, by an electronic Messaging System; and

(d) Automatic action of high-set under-frequency relays as a result of a significant frequency deviation.

(3) ERCOT shall deploy Responsive Reserve to respond to a frequency deviation when the power requirement to restore frequency to normal ACE in ten minutes exceeds the Reg-Up ramping capability. Deployment of Responsive Reserve on Load Resources, excluding Controllable Load Resources, must be as described in Section 6.5.9.4, Emergency Electric Curtailment Plan.

(4) ERCOT may deploy Responsive Reserve in response to NERC Disturbance Control Assistance requirements as specified in the Operating Guides if no additional energy is available to be dispatched from SCED as determined by the Ancillary Services Capacity Monitor.

(5) Energy from Responsive Reserve Resources may also be deployed by ERCOT under Section 6.5.9, Emergency Operations.

(6) ERCOT shall allocate the deployment of Responsive Reserve proportionally among QSEs that provide Responsive Reserve using Resources that are not on high-set under frequency relays. If ERCOT has deployed 500 MW of Responsive Reserve, and additional Responsive Reserve is needed, ERCOT shall declare that an EECP is in effect and shall follow provisions in Section 6.5.9, Emergency Operations.

(7) ERCOT shall use the SCED and Non-Spin as soon as practicable to minimize the prolonged use of Responsive Reserve Energy.

(8) Once Responsive Reserve is deployed, the QSE's obligation to deliver Responsive Reserve remains in effect until specifically instructed by ERCOT to stop providing Responsive Reserve. However, except in an Emergency Condition, the QSE's obligation to deliver Responsive Reserve may not exceed the period for which the service was committed.

(9) Following the deployment or recall of a deployment by Dispatch Instruction of Responsive Reserve, ERCOT shall adjust the HASL and LASL based on the QSE's telemetered Ancillary Service Schedule for Responsive Reserve to account for such deployment.

(10) A Controllable Load Resource is recalled by ERCOT Operator Dispatch Instruction subject to its normal ramp rate.

(11) QSEs providing Responsive Reserve and ERCOT shall meet the deployment performance requirements specified in Section 8, Performance Monitoring and Compliance.

(12) ERCOT shall issue Responsive Reserve deployment Dispatch Instructions over ICCP for Generation Resources and Controllable Load Resources and XML for all other Load Resources. Those Dispatch Instructions must contain the MW output requested.

(13) To the extent that ERCOT deploys a Load Resource that has chosen a block deployment option, ERCOT shall either deploy the entire offer or, if only partial deployment is possible, skip the offer by the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(14) The amount of RRS that a QSE can self-arrange using a Load Resource that is not a Controllable Load Resource is limited to the percentage amount of total RRS that the Load Resource can provide as specified by ERCOT. However, a QSE may offer additional Load Resources into the ERCOT RRS Ancillary Service market.

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

(1) ERCOT shall deploy Non-Spinning Reserve Service using SCED for On-Line Generation Resources with Energy Offer Curves and by Operator Dispatch Instruction for Resources with Output Schedules, Off-Line Generation Resources and Load Resources. ERCOT shall develop a procedure approved by TAC to deploy Resources providing Non-Spinning Reserve Service. ERCOT Operators shall implement the deployment procedure when a specified threshold(s) in MW of capability available to SCED to increase generation is reached. ERCOT Operators may implement the deployment procedure to recover deployed Responsive Reserve or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that scheduled on an individual Resource.

(2) Once Generation Resources providing Non-Spin are deployed and On-Line, ERCOT shall use SCED to determine the amount of energy to be dispatched from those Resources.

(3) Off-Line Generation Resources providing Non-Spin (OFFNS Resource Status) are required to provide an Energy Offer Curve for use by SCED.

(4) On receipt of a Dispatch Instruction, Load Resource providing Non-Spin must, at a minimum, provide the requested deployment energy within 30 minutes of the Dispatch Instruction. On receipt of a Dispatch Instruction, Off Line Generation providing Non-Spin must be online and be able to dispatch to its Non-Spin Resource Responsibility within 30 minutes of the Dispatch Instruction.

(5) Once the On-Line Non-Spin Resource has been deployed for energy, ERCOT will automatically calculate new HASL constraints for SCED assuming the Resource's Non-Spin Ancillary Service Schedule is reduced to the amount of the deployment. On

deployment of Off-Line Non-Spin Resources, the QSE will indicate the Non-Spin Ancillary Service Schedule is reduced by the amount of the deployment.

(6) For Dynamically Scheduled Resources (DSRs) providing Non-Spin, on deployment of Non-Spin, the DSR's QSE shall adjust its Resource Output Schedule to reflect the amount of deployment. For non-DSRs with Output Schedules providing Non-Spin, on deployment of Non-Spin, ERCOT shall adjust the Resource Output Schedule for the remainder of the Operating Period to reflect the amount of deployment. ERCOT shall notify the QSEs representing the non-DSR of the adjustment through the MIS Certified Area.

(7) For On-Line Generation Resources with Energy Offer Curves, Base Points include Non-Spin energy as well as any other energy dispatched as a result of SCED.

(8) Each QSE providing Non-Spin from a Resource shall inform ERCOT of the Non-Spin Resource availability using the Resource Status indications for the Operating Hour using telemetry and shall use the COP to inform ERCOT of Non-Spin Resource Status for hours in the Adjustment Period through the end of the Operating Day.

(9) ERCOT may deploy Non-Spin at any time in a Settlement Interval.

(10) ERCOT's Non-Spin Dispatch Instructions for deployment of Resources with Output Schedules, Off-Line Generation Resources and Load Resources must include:

(a) The Resource name;

(b) A MW level of capacity deployment for Off-Line Generation Resources, a MW level of energy for Resources with Output Schedules, and interrupted amount for Load Resources; and

(c) The anticipated duration of deployment.

(11) ERCOT shall, as part of its TAC-approved Non-Spin deployment procedure, provide for the recall of Non-Spin energy including descriptions of changes to Output Schedules and release of energy obligations from On-Line Resources with Output Schedules and from On-Line Resources that were previously Off-Line Resources providing Non-Spin capacity.

(12) Non-Spin procured from a Load Resource block offer must be deployed as a block.

6.5.7.7 Voltage Support Service

(1) ERCOT shall coordinate with TSPs the creation and maintenance of Voltage Profiles as described in Section 3.15, Voltage Support.

(2) ERCOT, or TSPs designated by ERCOT, shall instruct QSEs having Generation Resources required to provide Voltage Support Service (VSS), to make adjustments for voltage support within the Unit Reactive Limit (URL) provided by the QSE to ERCOT.

A Generation Resource providing VSS may not be requested to reduce MW output so as to provide additional reactive (Mvar), nor may they be requested to operate on a voltage schedule outside the URL specified by the QSE without a Dispatch Instruction requesting Resource-specific Dispatch.

(3) ERCOT and TSPs shall develop operating procedures specifying Voltage Profiles of transmission-controlled reactive resources to minimize the dependence on generation-supplied reactive resources. For Generation Resources required to provide VSS, step-up transformer tap settings must be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

(4) Each TSP, under ERCOT's direction, is responsible for monitoring and ensuring that all Generation Resources required to provide VSS dynamic reactive sources in a local area are deployed in approximate proportion to their respective installed reactive capability requirements.

(5) Each Generation Resource required to provide VSS shall maintain the transmission voltage at the point of interconnection to the ERCOT Transmission Grid as directed by ERCOT within the operating Reactive Power capability of the Resource.

(6) Whenever a Generation Resource is On-Line and available for energy deployment, it is required to provide VSS up to its URL. The URL must be available for utilization at the Resource's continuous rated active power output, and Reactive Power up to the Resource's operating capability must be available for utilization at lower active power output levels. In no event may the Reactive Power available be less than the required installed reactive capability multiplied by the ratio of the lower active power output to the Resource's continuously rated active power output, and any Reactive Power available for utilization must be fully deployed to support system voltage upon request by ERCOT, or a TSP.

(7) Each QSE providing VSS shall meet the deployment performance requirements specified in Section 8, Performance Monitoring and Compliance.

6.5.7.8 Dispatch Procedures

(1) ERCOT shall issue all Resource Dispatch Instructions to the QSE that represents the affected Resource. ERCOT may not issue Dispatch Instructions to the QSE for Resources with a Resource Status of ONTEST (which indicates that it is undergoing testing), except:

(a) For Dispatch Instructions that are a part of the testing; or

(b) During conditions when the Resource is the only alternative for solving a transmission constraint; or

(c) During Force Majeure Events that threaten the reliability of the ERCOT System.

(2) Each QSE shall immediately forward any valid Dispatch Instruction to the appropriate Resource or group of Resources or identify a reason for non-compliance with the Dispatch Instruction to ERCOT in accordance with Section 6.5.7.9, Compliance with Dispatch Instructions.

(3) If ERCOT believes that a Resource has inadequately responded to a Dispatch Instruction, ERCOT shall notify the QSE representing the Resource as soon as practicable.

(4) The recipient of a VDI shall confirm the Dispatch Instruction by providing the receiving operator's identification and by repeating the VDI to ERCOT orally.

(5) The recipient of an electronic Dispatch Instruction shall acknowledge receipt of the Dispatch Instruction to ERCOT electronically, within one minute. The electronic acknowledgement must include the receiving operator's identification.

(6) The recipient of any Dispatch Instruction shall immediately request clarification of the Dispatch Instruction if the recipient fails to understand its responsibility under the Dispatch Instruction.

(7) ERCOT shall record all voice conversations that occur in the communication of Dispatch Instructions.

(8) ERCOT shall record and file all electronic Dispatch Instructions and acknowledgements as soon as practicable after the issuance of the Dispatch Instruction.

(9) By mutual agreement of the TSP and ERCOT, Dispatch Instructions to the TSP may be provided to the TSP's Designated Agent. In that case, issuance of the Dispatch Instruction to the Designated Agent is considered issuance to the TSP, and the TSP must comply with the Dispatch Instruction exactly as if it had been issued directly to the TSP, whether or not the Designated Agent accurately conveys the Dispatch Instruction to the TSP.

6.5.7.9 Compliance with Dispatch Instructions

(1) Except as otherwise specified in this Section, each TSP and each QSE shall comply fully and promptly with a Dispatch Instruction issued to it, unless in the sole and reasonable judgment of the TSP or QSE, such compliance would create an undue threat to safety, undue risk of bodily harm or undue damage to equipment, or the Dispatch Instruction is otherwise not in compliance with these Protocols.

(2) If the recipient of a Dispatch Instruction does not comply because in the sole and reasonable judgment of the TSP or QSE, such compliance would create an undue threat to safety, undue risk of bodily harm, or undue damage to equipment, then the TSP or QSE must immediately notify ERCOT and provide the reason for non-compliance.

(3) If the recipient of a Dispatch Instruction recognizes that the Dispatch Instruction conflicts with other valid instructions or is invalid, the recipient shall immediately notify ERCOT

of the conflict and request resolution. ERCOT shall resolve the conflict by issuing another Dispatch Instruction.

(4) ERCOT's final Dispatch Instruction to a QSE in effect applies for all Protocol-related processes. If the QSE does not comply after receiving the final Dispatch Instruction, the QSE remains liable for failure to meet its obligations under the Protocols and remains liable for any charges resulting from such failure.

(5) ERCOT's final Dispatch Instruction to a TSP in effect applies for all Protocol-related processes. If the TSP does not comply after receiving the final Dispatch Instruction, the TSP remains liable for such failure under these Protocols under the TSP's Agreement with ERCOT.

(6) In all cases in which compliance with a Dispatch Instruction is disputed, both ERCOT and the QSE or TSP shall document their communications, agreements, disagreements, and reasons for their actions, to enable resolution of the dispute through the ADR process in Section 20, Alternative Dispute Resolution Procedure.

(7) An Intermittent Renewable Resources (IRR) must comply with Dispatch Instructions requiring it to reduce output two MW or more below the Resource's latest HSL.

6.5.8 Verbal Dispatch Instructions

A VDI must contain the following information:

(a) Identification of the responsible Entity and instructing authority (to include ERCOT Operator's and receiving operator's names);

(b) Specific Resources or TSP facilities that are the subject of the Dispatch Instruction;

(c) Specific action required;

(d) Current operating level or state of the Resources or TSP facilities that are the subject of the Dispatch Instruction;

(e) Operating level or state to which such Resources or facilities will be dispatched;

(f) Time of notification of the Dispatch Instruction;

(g) Time at which the QSE or TSP is required to initiate the Dispatch Instruction;

(h) Time within which the QSE or TSP is required to complete the Dispatch Instruction;

(i) VDI reference number; and

(j) Other information relevant to that Dispatch Instruction.

6.5.9 Emergency Operations

(1) ERCOT, based on ERCOT System reliability needs, may issue a Dispatch Instruction requiring a Resource to move to a specific output level ("Emergency Base Point").

(2) A QF may only be ordered Off-Line in the case of an ERCOT-declared Emergency Condition with imminent threat to the reliability of the ERCOT System. ERCOT may only Dispatch a QF below its LSL when ERCOT has declared an Emergency Condition and the QF is the only Resource that can provide the necessary relief.

(3) ERCOT shall honor all Resource operating parameters in Dispatch Instructions under normal conditions and Emergency Conditions. During Emergency Conditions, ERCOT may verbally request QSEs to operate its Resources outside normal operating parameters. If such request is received by a QSE, the QSE shall discuss the request with ERCOT in good faith and may choose to comply with the request.

(4) A QSE may not self-arrange for Ancillary Services procured in response to Emergency Conditions.

6.5.9.1 Emergency and Short Supply Operation

(1) ERCOT, as the single Control Area Operator, is responsible for maintaining reliability in normal and emergency operating conditions. The Operating Guides are intended to ensure that minimum standards for reliability are maintained. Minimum standards for reliability are defined by the Operating Guides and the NERC standards and include, but are not limited to:

(a) Minimum operating reserve levels;

(b) Criteria for determining acceptable operation of the frequency control system;

(c) Criteria for determining and maintaining system voltages within acceptable limits;

(d) Criteria for maximum acceptable transmission equipment loading levels; and

(e) Criteria for determining when ERCOT is subject to unacceptable risk of widespread cascading outages.

(2) ERCOT shall, to the fullest extent practicable, utilize the Day-Ahead process, the Adjustment Period process, and the Real-Time process before ordering Resources to specific output levels with Emergency Base Point instructions. It is anticipated that, with effective and timely communication, the market-based tools available to ERCOT will avert most threats to the reliability of the ERCOT System. However, these Protocols do not preclude ERCOT from taking any action to preserve the integrity of the ERCOT System.

(3) Under an Emergency Condition, the ERCOT Operator may relax transmission constraints to provide additional generation at the expense of temporarily creating a security

violation as long as the violation does not physically overload any single Transmission Element above its emergency limit, as defined in the ERCOT Operating Guides. ERCOT shall report any NERC or Federal Energy Regulatory Commission (FERC) penalties assessed for violating those constraints to Market Participants and the Public Utility Commission of Texas (PUCT).

6.5.9.2 Failure of the SCED Process

(1) When the SCED process is not able to reach a solution, ERCOT shall declare an Emergency Condition.

(2) For intervals that the SCED process fails to reach a solution, then the LMPs for the interval for which no solution was reached are equal to the LMPs in the most recently solved interval. ERCOT shall notify the market of the failure using the Messaging System and by posting on the MIS Secure Area.

(3) Once ERCOT declares an Emergency Condition for a SCED process failure, ERCOT may use any of the following measures:

(a) ERCOT may direct the SCED process to relax the active transmission constraints and/or the HASLs and LASLs for specific Resources and resume calculation of LMPs by reducing the Ancillary Service Schedules for the affected Resource, if sufficient supply exists to manage total system needs. LMPs calculated for the affected interval must be used for Settlement;

(b) ERCOT may issue Emergency Base Points for Resources;

(c) ERCOT may manually issue Emergency Base Points for a Resource and must communicate the Resource name, MW output requested, and start time and duration of the Dispatch Instruction to the QSE representing the Resource.

(d) ERCOT may issue an instruction to hold the previous interval.

(e) A QF, a hydro-powered Resource, or a nuclear-powered Resource may be instructed by ERCOT to operate below its Low Sustained Limit only after all other Resource options have been exhausted.

(4) The Emergency Condition continues until the SCED process can reach a solution without using the measures in paragraph (3) of Section 6.5.9.2, Failure of the SCED Process.

6.5.9.3 Communication under Emergency Conditions

(1) Effective, accurate, and timely communication between ERCOT, TSPs, and QSEs is essential. Each QSE must be provided adequate information to make informed decisions and must receive the information with sufficient advance notice to facilitate Resource and load responses.

(2) The type of communication ERCOT issues is determined primarily on the basis of the time available for the market to respond before an Emergency Condition occurs. The timing of these communications could range from days in advance to immediate. If there is insufficient time to allow the market to react, ERCOT may bypass one or more of the communication steps.

(3) ERCOT shall consider the severity of the potential Emergency Condition as it determines which of the communications set forth in Section 6.5.9.1, Emergency and Short Supply Operation, to use. The severity of the Emergency Condition could be limited to an isolated local area, or the condition might cover large areas affecting several entities, or the condition might be an ERCOT-wide condition potentially affecting the entire ERCOT System.

(4) The following sections describe the types of communications that will be issued by ERCOT to inform all QSEs and TSPs of the operating situation. These communications may relate to transmission, distribution, or Generation or Load Resources. The communications must specify the severity of the situation, the area affected, the areas potentially affected, and the anticipated duration of the Emergency Condition.

6.5.9.3.1 Operating Condition Notice

(1) ERCOT will issue an Operating Condition Notice (OCN) to inform all QSEs of a possible future need for more Resources due to conditions that could affect ERCOT System reliability. OCNs are for informational purposes only, and ERCOT exercises no additional operational authority with the issuance of this type of notice, but may solicit additional information from QSEs in order to determine whether the issuance of an Advisory, Alert, or Emergency Notice is warranted. The OCN is the first of four possible levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

(2) When time permits, ERCOT will issue an OCN before issuing an Advisory, Alert, or Emergency Notice. However, issuance of an OCN may not require action on the part of any Market Participant, but rather serves as a reminder to QSEs and TSPs that some attention to the changing conditions may be warranted. OCNs serve to communicate to QSEs the need to take extra precautions to be prepared to serve the Load during times when contingencies are most likely to arise.

(3) Reasons for OCNs include unplanned transmission Outages, and weather-related concerns such as anticipated freezing temperatures, hurricanes, wet weather, and ice storms.

(4) ERCOT will monitor actual and forecasted weather for the ERCOT Region and adjacent NERC regions. When adverse weather conditions are expected, ERCOT may confer with TSPs and QSEs regarding the potential for adverse reliability impacts and contingency preparedness. Based on its assessment of the potential for adverse conditions, ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no

more than seven days from the date of the request. The specific information that may be requested shall be defined in the Operating Guides. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

(5) QSEs and TSPs are expected to establish and maintain internal procedures for monitoring actual and forecasted weather and for implementing appropriate measures when the potential for adverse weather or other conditions (which could threaten ERCOT System reliability) arise.

6.5.9.3.2 Advisory

(1) An Advisory is the second of four possible levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

(2) ERCOT shall issue an Advisory for the following reasons:

(a) When it recognizes that conditions are developing or have changed and more Ancillary Services will be needed to maintain current or near-term operating reliability;

(b) When weather or ERCOT System conditions require more lead-time than the normal Day-Ahead Market allows;

(c) When communications or other controls are significantly limited; or

(d) When ERCOT Transmission Grid conditions are such that operations within first contingency criteria as defined in the Operating Guides are not likely or possible because of Forced Outages or other conditions.

(3) The Advisory must communicate existing constraints. ERCOT shall notify TSPs and QSEs of the Advisory, and QSEs shall notify appropriate Resources and Load Serving Entities (LSEs). ERCOT shall communicate with TSPs as needed to confirm their understanding of the condition and to determine the availability of Transmission Facilities. For the purposes of verifying submitted information, ERCOT may communicate with QSEs.

(4) Although an Advisory is for information purposes, ERCOT may exercise its authority, in such circumstances, to increase Ancillary Service requirements above the quantities originally specified in the Day-Ahead in accordance with procedures. ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no more than seven days from the date of the request. The specific information that may be requested shall be defined in the Operating Guide. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

6.5.9.3.3 Alert

(1) An Alert is the third of four possible levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

(2) ERCOT shall issue an Alert when ERCOT determines that:

(a) Conditions have developed such that additional Ancillary Services are needed in the current Operating Period;

(b) There are insufficient Ancillary Services or Energy Offers. in the Day-Ahead Market (DAM) or in a Supplemental Ancillary Services Market (SASM)

(c) Market-based congestion management techniques embedded in SCED as specified in these Protocols will not be adequate to resolve transmission security violations;

(d) Forced Outages or other abnormal operating conditions have occurred, or may occur that require operations with active transmission security violations; or

(3) With the issuance of an Alert pursuant to item (2)(a) above, ERCOT may exercise its authority to immediately procure the following services from existing offers:

(a) Regulation Services;

(b) RRS services; and

(c) Non-Spinning Reserve Services.

(4) If the actions in paragraph (3) above do not relieve the insufficiency described in paragraph (2)(a) above, then ERCOT may issue Dispatch Instructions to Resources certified to provide the insufficient service, even though there is not an existing Ancillary Service Offer for that Resource.

(5) If ERCOT issues an Alert because insufficient Ancillary Service Offers were received in the DAM, and if the Alert does not result in sufficient offer and the DAM is executed with insufficient offers, then ERCOT shall acquire the insufficient amount of Ancillary Services in the Day-Ahead Reliability Unit Commitment (DRUC) and shall issue Dispatch Instructions to the QSEs for Resources that were RUC-Committed to provide Ancillary Services, informing them of the requirement that the Resources be prepared to provide those Ancillary Services.

(6) If ERCOT issues an Alert because insufficient Ancillary Service Offers were received in a SASM, and if the Alert does not result in sufficient offer and the SASM is executed with insufficient offers, then ERCOT shall acquire the insufficient amount of Ancillary Services in the next Hourly Reliability Unit Commitment (HRUC) and shall issue Dispatch Instructions to the QSEs for Resources that were RUC-Committed to provide

Ancillary Services, informing them of the requirement that the Resources be prepared to provide those Ancillary Services.

(7) ERCOT shall post the Alert message electronically to the MIS Secure Area and shall provide verbal notice to all TSPs and QSEs via the Hotline. Corrective actions identified by ERCOT must be communicated through Dispatch Instructions to all TSPs, DSPs and QSEs required to implement the corrective action. Each QSE shall immediately notify the Market Participants that it represents of the Alert. To minimize the effects on the ERCOT System, each TSP or DSP shall identify and prepare to implement actions, including restoration of transmission lines as appropriate and preparing for Load shedding. ERCOT may instruct TSPs or DSPs to reconfigure ERCOT System elements as necessary to improve the reliability of the ERCOT System. On notice of an Alert, each QSE, TSP, and DSP shall prepare for an emergency in case conditions worsen. ERCOT may require information from QSEs representing Resources regarding the Resources' fuel capabilities. Requests for this type of information shall be for a time period of no more than seven days from the date of the request. The specific information that may be requested shall be defined in the Operating Guide. QSEs representing Resources shall provide the requested information in a timely manner, as defined by ERCOT at the time of the request.

6.5.9.3.4 Emergency Notice

(1) Emergency Notice is the fourth of four possible levels of communication issued by ERCOT in anticipation of a possible Emergency Condition.

(2) ERCOT shall issue an Emergency Notice only for one or more of the following reasons:

(a) ERCOT cannot maintain minimum reliability standards (for reasons including fuel shortages) during the Operating Period using every Resource practicably obtainable from the market;

(b) ERCOT is in an unreliable condition, as defined below;

(c) Immediate action must be taken to avoid or relieve an overloaded Transmission Element;

(d) ERCOT varies from timing requirements or omits one or more Day-Ahead or Adjustment Period and Real-Time procedures;

(e) ERCOT varies from timing requirements or omits one or more scheduling procedures in the Real-Time process; or

(f) The SCED process fails to reach a solution, whether or not ERCOT is using one or both of the measures specified in paragraph (3) of Section 6.5.9.2, Failure of the SCED Process.

(3) The actions ERCOT takes during an Emergency Condition depend on the nature and severity of the situation.

(4) ERCOT is considered to be in an unreliable condition whenever ERCOT Transmission Grid status is such that the most severe single-contingency event presents the threat of uncontrolled separation or cascading outages and/or large-scale service disruption to Load (other than Load being served from a radial transmission line) and/or overload of a critical Transmission Element, and no timely solution is obtainable through market processes.

(5) If the Emergency Condition is the result of a transmission problem that puts the ERCOT System in an unreliable condition, then ERCOT shall act immediately to return the ERCOT System to a reliable condition, including instructing Resources to change output and instructing TSPs or DSPs to drop Load.

(6) If the Emergency Condition is the result of an Ancillary Service insufficiency, then ERCOT shall follow the EECP procedures.

6.5.9.4 Emergency Electric Curtailment Plan

(1) At times it may be necessary to reduce ERCOT System Demand because of a temporary decrease in available electricity supply. To provide orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT shall initiate and coordinate the implementation of the EECP following the steps set forth below in Section 6.5.9.4.2, EECP Steps.

(2) The goal of the EECP is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT System to reduce the chance of cascading Outages.

(3) ERCOT's operating procedures must meet the following goals:

(a) Use of market processes to the fullest extent practicable without jeopardizing the reliability of the ERCOT System;

(b) Use of RRS services, other Ancillary Services, and Emergency Interruptible Load Service (EILS) to the extent permitted by ERCOT System conditions;

(c) Maximum use of ERCOT System capability;

(d) Maintenance of station service for nuclear-powered Generation Resources;

(e) Securing startup power for Generation Resources;

(f) Operation of Generation Resources during loss of communication with ERCOT; and

(g) Restoration of service to Loads in the manner defined in the Operating Guides.

(4) ERCOT is responsible for coordinating with QSEs, TSPs, and DSPs to monitor ERCOT System conditions, initiating the EECP steps, notifying all QSEs, and coordinating the implementation of the EECP steps while maintaining transmission security limits.

(5) ERCOT, at management's discretion, may at any time issue an appeal through the public news media for voluntary energy conservation.

(6) During the EECP, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using the DC Ties or by using Block Load Transfers (BLTs) to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with NERC scheduling guidelines.

(7) Some of the EECP steps are not applicable if transmission security violations exist. There may be insufficient time to implement all EECP steps in sequence, however, to the extent practicable, ERCOT shall use Ancillary Services that QSEs have made available in the market to maintain or restore reliability.

(8) ERCOT may immediately implement Step 4 of the EECP any time the steady-state system frequency is below 59.8 Hz and shall immediately implement Step 4 any time the steady-state frequency is below 59.5 Hz.

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

6.5.9.4.1 General Procedures Prior to EECP Operations

(1) Prior to declaring EECP Step 1 detailed in Section 6.5.9.4.2, EECP Steps, ERCOT may perform the following operations consistent with Good Utility Practice:

  (a) Provide Dispatch Instructions to QSEs for specific Resources to operate at an Emergency Base Point to maximize Resource deployment so as to increase Responsive Reserve levels on other Resources;

  (b) Commit available Resources as necessary that can respond in the timeframe of the emergency. Such commitments will be settled using the HRUC process;

  (c) Start RMR Units available in the time frame of the emergency. RMR Units should be loaded to full capability;

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

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

(f) ERCOT shall use the PRC to determine the appropriate emergency Notification and EECP steps.

(2) In addition, ERCOT may issue an appeal through the public news media for voluntary Load reduction if authorized by the ERCOT Chief Executive Officer or its designee based on an evaluation of existing and anticipated system conditions.

6.5.9.4.2 EECP Steps

(1) Step 1 - Maintain a sum total of 2,300 MW that results from adding the amount of ERCOT PRC MW (Section 6.5.7.5, Ancillary Services Capacity Monitor) and the amount of RRS MW which is supplied from Load Resources.

(a) ERCOT will:

(i) Notify the Southwest Power Pool Security Coordinator;

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

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

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

(2) Step 2 - Maintain a sum total of 1,750 MW that results from adding the amount of ERCOT PRC MW (Section 6.5.7.5) and the amount of RRS MW which is supplied from Load Resources.

(a) In addition to the measures associated with Step 1, ERCOT:

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

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

(A) Instruct QSEs to deploy half of the Responsive Reserve that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 1 Load Resources providing Responsive Reserve. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from Group 2 if

Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

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

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

(D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource obligation which may be deployed to interrupt under paragraph (A), Group 1 and paragraph (B), Group 2. ERCOT shall develop a process for determining which individual Load Resource to place in Group 1 and which to place in Group 2. ERCOT procedures shall select Group 1 and Group 2 based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EECP Step 2;

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

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

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

(3) Step 3 - Maintain system frequency at 60 Hz. Following deployment of the measures associated with Steps 1 and 2, ERCOT will deploy available contracted EILS Loads, via a single VDI to the all-QSE Hotline; as follows:

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

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

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

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

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

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

(4) Step 4 - Maintain system frequency at 59.8 Hz or greater.

(a) In addition to measures associated with Steps 1, 2 and 3, ERCOT will direct all TSPs and DSPs or their agents to shed firm load, in 100 MW blocks, as documented in the ERCOT Operating Guides in order to maintain a steady state system frequency of 59.8 Hz.

(b) In addition to measures associated with Steps 1, 2 and 3, TSPs and DSPs will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TSPs and DSPs shall not manually drop load connected to under-frequency relays during the implementation of the EECP.

6.5.9.4.3 Restoration of Market Operations

ERCOT shall continue EECP until sufficient offers are received and deployed by ERCOT to eliminate the conditions requiring the EECP and normal SCED operations are restored. ERCOT shall release EILS Loads after the restoration of Responsive Reserve. Intermittent solutions of SCED do not set new LMPs until ERCOT declares that the EECP is no longer needed.

6.5.9.5 Block Load Transfers between ERCOT and Non-ERCOT Control Areas

BLTs are procedures that transfer Loads normally located in the ERCOT Control Area to a Non-ERCOT Control Area. Similarly, when a Non-ERCOT Control Area experiences certain transmission contingencies or short-supply conditions, ERCOT may agree to the implementation of BLT procedures that transfer Loads normally located in a Non-ERCOT Control Area to the ERCOT Control Area. BLTs are restricted to the following conditions:

(a) BLTs may occur only under a specific Dispatch Instruction from ERCOT.

(b) BLTs that are comprised of looped systems may be tied to the other Control Area's electrical system(s) through multiple interconnection points at the same time. Transfers of looped configurations are permitted only if all interconnection points are netted under a single Electric Service Identifier (ESI ID).

(c) BLTs of Load to the ERCOT Control Area are:

(i) Treated as non-competitive wholesale Load in the Load Zone containing the ERCOT breaker or switch that initiated the BLT;

(ii) Registered in a manner similar to that of Non-Opt-In Entities;

(iii) Responsible for Unaccounted For Energy (UFE) allocations and Transmission Losses consistent with similarly situated Non Opt-In Entity metering points; and

(iv) Permitted only if the BLT will not jeopardize the reliability of the ERCOT System. Under an Emergency Notice, BLTs that have been implemented may be curtailed or terminated by ERCOT to maintain the reliability of the ERCOT System.

(d) BLTs of Load from the ERCOT Control Area are treated as Resources in the ERCOT Settlement system and may only be instructed with the permission of the affected Non-ERCOT Control Area. Under an Emergency Condition, BLTs that have been implemented may be curtailed or terminated by the Non-ERCOT Control Area to maintain the reliability of the Non-ERCOT system.

(e) BLTs specifically exclude transfers of Load between ERCOT and Non-ERCOT Control Areas that occur behind a retail Settlement Meter.

(f) BLTs may be used in the restoration of service to customers if the transfers will not jeopardize the reliability of the ERCOT System.

(g) The necessary Market Participant agreements, metering, and ERCOT Settlement systems must be in place before ERCOT may implement any BLT.

(h) BLT metering points connected to the ERCOT Transmission Grid used five or more time per year, as monitored by the TSP, must conform to ERCOT-Polled

Settlement (EPS) Metering requirements as defined in Section 10, Metering, and the Settlement Metering Operating Guides. All other BLT metering points must be revenue quality, four channel bi-directional kWh/kvarh, 15-minute Interval Data Recording (IDR) metering with remote interrogation. ERCOT may impose additional metering requirements it considers necessary to ensure ERCOT System reliability and integrity.

(i) SCADA telemetry on switching devices at BLT points must be provided.

6.5.9.5.1 Registration and Posting of BLT Points

(1) BLTs that block ERCOT Load into a non-ERCOT Control Area are treated as a Resource by ERCOT and assigned a Resource ID. The TSP or DSP associated with the BLT Point has the responsibility for creation and maintenance of BLT Resource IDs. An ERCOT-registered Resource Entity with an ERCOT-registered QSE affiliation must complete the applicable asset registration forms. This asset registration form along with the metering design documentation is the basis for establishing the ERCOT data model of the BLT.

(2) BLTs that block Non-ERCOT Load into the ERCOT System are treated as a non-competitive wholesale Load by ERCOT and assigned an ESI ID. The TSP or DSP associated with the BLT Point has the responsibility for creation and maintenance of BLT ESI IDs. Customers connected to the ERCOT System do not require an ESI ID if they are located behind BLT Points. The TSP or DSP that creates the BLT Point shall provide the ESI ID associated with the BLT to ERCOT as well as notify ERCOT of the ERCOT registered LSE, and the QSE affiliation of the LSE associated with the BLT.

(3) A "BLT Point" is the metering point for a BLT Resource ID or for a BLT ESI ID.

(4) ERCOT shall post the registration details of all registerd BLTs to the MIS Secure Area.

6.5.9.5.2 Scheduling and Operation of BLTs

(1) The QSE for the Resource associated with a BLT Point shall include that Resource in its COP. The QSE is not required to provide the Real-Time data for the BLT Point to ERCOT as would normally be provided on behalf of Resources. The COP must show the availability of the Resource, but ERCOT shall confirm its availability with the Non-ERCOT system before issuing any Dispatch Instructions to the QSE and the TDSP. Any energy delivered under such a Dispatch Instruction is treated as an Emergency Base Point instruction to the QSE.

(2) Generation Resources connected to the portion of the ERCOT Transmission Grid included in the BLT are under no obligation, under these Protocols, to provide Ancillary Services or any other services to ERCOT while that portion of the ERCOT Transmission Grid is connected to a non-ERCOT system other than through a DC Tie.

(3) ERCOT shall continue to include the BLT Point Load in the Settlement of the LSE Load Obligations.

6.5.9.6 Black Start

(1) Black-Start Service is obtained by ERCOT through Black Start Agreements with QSEs for Generation Resources capable of self-starting or Generation Resources within close proximity of a non-ERCOT Control Area that are capable of starting from that non-ERCOT Control Area under a firm standby power supply contract, without support from the ERCOT System, or transmission equipment in the ERCOT System. Generation Resources that can be started with a minimum of pre-coordinated switching operations using ERCOT transmission equipment within the ERCOT System may be considered for Black Start Service only where switching may be accomplished within one hour or less.

(2) ERCOT may Dispatch Black-Start Service pursuant to an emergency restoration plan to begin restoration of the ERCOT System to a secure operating state after a blackout. ERCOT shall include in the restoration plan specific instructions for all Market Participants, including TSPs and DSPs, describing actions to be taken on loss of communication and other general restoration actions. ERCOT shall post the restoration plan on the MIS Secure Area within 14 days of creation or update.

6.6 Settlement Calculations for the Real-Time Energy Operations

6.6.1 Real-Time Settlement Point Prices

Real-Time energy settlements use Real-Time Settlement Point Prices (SPPs) that are calculated for Resource Nodes, Load Zones, and Hubs.

6.6.1.1 Real-Time Settlement Point Price for a Resource Node

The Real-Time SPP for a Resource Node Settlement Point is a Base-Point time-weighted average of the Real-Time Locational Marginal Prices (LMPs). The Real-Time SPP for a 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTSPP} = \sum_{y} (\textbf{RNWF}_{y} * \textbf{RTLMP}_{y})$$

Where the Resource Node weighting factor is:

$$\textbf{RNWF}_{y} = [\textbf{Max}\ (0.001, \sum_{r} \textbf{BP}_{r,\,y}) * \textbf{TLMP}_{y}] \,/\, [\sum_{y} (\textbf{Max}\ (0.001, \sum_{r} \textbf{BP}_{r,\,y}) * \textbf{TLMP}_{y})]$$

The above variables are defined as follows:

Variable	Unit	Description

RTSPP	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time SPP at the Settlement Point for the 15-minute Settlement Interval.
$RTLMP_{y}$	\$/MWh	*Real-Time Locational Marginal Price per interval*—The Real-Time LMP at the Settlement Point for the Security-Constrained Economic Dispatch (SCED) interval *y*.
$BP_{r, y}$	MW	*Base Point per Resource per interval*—The Base Point of Resource *r*, for the whole SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node SPP calculation for the portion of the SCED interval y within the Settlement Interval.
$TLMP_{y}$	second	*Duration of SCED interval per interval* – The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
r	none	A Resource at the Resource Node. The summation is taken over all Resources at that node.

6.6.1.2 Real-Time Settlement Point Price for a Load Zone

The Real-Time SPP for a Load Zone Settlement Point is based on the state-estimated Load in MW and the time-weighted average Real-Time LMPs at Electrical Buses that are included in the Load Zone. The Real-Time SPP for a Load Zone Settlement Point for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP} = \sum_{y}\sum_{b} (\mathbf{RTLMP}_{b,y} * \mathbf{LZWF}_{b,y})$$

For all Load Zones except Direct Current Tie (DC Tie) Load Zones:

$$LZWF_{b,y} = (SEL_{b,y} * TLMP_{y}) / [\sum_{y}\sum_{b} (SEL_{b,y} * TLMP_{y})]$$

For a DC Tie Load Zone:

$$LZWF_{y} = [Max(0.001, SEL_{y}) * TLMP_{y})] / [\sum_{y} [Max(0.001, SEL_{y}) * TLMP_{y})]$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	\$/MWh	*Real-Time Settlement Point Price*—The Real-Time SPP at the Settlement Point, for the 15-minute Settlement Interval.
$RTLMP_{b, y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time SPP at Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$LZWF_{b, y}$	none	*Load Zone Weighting Factor per bus per interval*—The weight used in the Load Zone SPP calculation for Electrical Bus *b*, for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$SEL_{b, y}$	MW	*State Estimator Load at bus per interval*—The Load from State Estimator for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the

		total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

6.6.1.3 Real-Time Settlement Point Price for a Hub

The Real-Time SPP at a Hub is determined according to the methodology included in the definition of that Hub in Section 3.5.2, Hub Definitions.

6.6.2 Load Ratio Share

6.6.2.1 ERCOT Total Adjusted Metered Load

ERCOT total Adjusted Metered Load (excluding the DC Tie export associated with the Qualified Scheduling Entities (QSEs) under the "Oklaunion Exemption") for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTAMLTOT} = \sum_{q} \sum_{p} \mathbf{RTAML}_{\boldsymbol{q, p}}$$

The above variables are defined as follows:

Variable	Unit	Description
RTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total Adjusted Metered Load in ERCOT, for the 15-minute Settlement Interval.
RTAML $_{q, p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the Adjusted Metered Load at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
q	none	A QSE. The summation is over all of the QSEs with metered readings in that interval.
p	none	A Settlement Point. The summation is over all of the Settlement Points.

6.6.2.2 QSE Load Ratio Share for a 15-Minute Settlement Interval

Each QSE's Load Ratio Share (LRS) for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LRS}_{\boldsymbol{q}} = \left(\sum_{p} \mathbf{RTAML}_{\boldsymbol{q, p}}\right) / \mathbf{RTAMLTOT}$$

The above variables are defined as follows:

Variable	Unit	Description
LRS $_{q}$	none	*Load Ratio Share per QSE*—The LRS as defined in Section 2, Definitions and Acronyms, for QSE *q*, for the 15-minute Settlement Interval.
RTAML $_{q, p}$	MWh	*Real-Time Adjusted Metered Load per Settlement Point per QSE*—The sum of the Adjusted Metered Load at the Electrical Buses that are included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.

RTAMLTOT	MWh	*Real-Time Adjusted Metered Load Total*—The total Adjusted Metered Load in ERCOT, for the 15-minute Settlement Interval.
p	none	A Settlement Point. The summation is over all of the Settlement Points.

6.6.2.3 QSE Load Ratio Share for an Operating Hour

Each QSE's LRS for an Operating Hour is calculated as follows:

$$\mathbf{HLRS}_{q} = (\sum_{i=1}^{4} \sum_{p} \mathbf{RTAML}_{q,\,p,\,i}) \,/\, (\sum_{i=1}^{4} \mathbf{RTAMLTOT}_{i})$$

The above variables are defined as follows:

Variable	Unit	Description
HLRS_{q}	none	*Hourly Load Ratio Share per QSE*—The LRS as defined in Section 2, Definitions and Acronyms, for QSE *q*, for the hour.
$\text{RTAML}_{q,\,p,\,i}$	MWh	*Real-Time Adjusted Metered Load per Settlement Point per QSE by interval*—The sum of the Adjusted Metered Load at the Electrical Buses that are included in the Settlement Point *p*, represented by QSE *q* for the 15-minute Settlement Interval *i*.
RTAMLTOT_{i}	MWh	*Real-Time Adjusted Metered Load Total by interval*—The total Adjusted Metered Load in ERCOT, for the 15-minute Settlement Interval *i*.
p	none	A Settlement Point. The summation is over all of the Settlement Points.
i	none	A 15-minute Settlement Interval in the Operating Hour. The summation over all of the Settlement Intervals of the Operating Hour.

6.6.3 Real-Time Energy Charges and Payments

6.6.3.1 Real-Time Energy Imbalance Payment or Charge at a Resource Node

(1) The payment or charge to each QSE for Energy Imbalance Service is calculated based on the Real-Time SPP for the following amounts at a particular Resource Node Settlement Point:

(a) The energy produced by all its Generation Resources at the Settlement Point; plus

(b) The amount of its Self-Schedules with sink specified at the Settlement Point; plus

(c) The amount of its Energy Bids cleared in the Day-Ahead Market (DAM) at the Settlement Point; plus

(d) The amount of its Energy Trades at the Settlement Point where the QSE is the buyer; minus

(e) The amount of its Self-Schedules with source specified at the Settlement Point; minus

(f) The amount of its Energy Offers cleared in the DAM at the Settlement Point; minus

(g) The amount of its Energy Trades at the Settlement Point where the QSE is the seller

(2) The payment or charge to each QSE for Energy Imbalance Service at a Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:

If the Generation Resources at the Resource Node Settlement Point *p* are involved with a net metering scheme

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \{ \sum_{gsc} (\sum_{r} (\mathbf{GSPLITPER}_{q,r,gsc,p} * \mathbf{NMSAMTTOT}_{gsc}) + \mathbf{RTSPP}_{p} * [(\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4)] \}$$

Otherwise

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \mathbf{RTSPP}_{p} * \{ \sum_{r} \mathbf{RTMG}_{q,p,r} + (\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4) \}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTEIAMT_{q,p}$	$	*Real-Time Energy ImbalanceAmount per QSE per Settlement Point*—The payment or charge to QSE *q* for the Real-Time Energy Imbalance at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTMG_{q,r,p}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
$SSSK_{q,p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
$DAEP_{q,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
$RTQQEP_{q,p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
$SSSR_{q,p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.

DAES $_{q,\,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s Energy Offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q,\,p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
NMSAMTTOT $_{gsc}$	$	*Net Metering Settlement Payment*—The total payment to the entire facility with a net metering arrangement.
GSPLITPER $_{q,\,r,\,gsc,\,p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a net metering arrangement. GSPLITPER is calculated by taking the Supervisory Control and Data Acquisition (SCADA) values (GSSPLITSCA) for a particular Generation Resource *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource.
gsc	none	A generation site code.

(3) The total payments to a facility with a net metering arrangement, for each 15-minute Settlement Interval, shall be calculated as follows:

$$\textbf{NMRTETOT}_{gsc} = \sum_{me} \textbf{MEB}_{gsc,\,b}$$

If NMRTETOT $_{gsc}$ = 0

The Load is included in the Real-Time Adjusted Metered Load per QSE and is included in the Real-Time energy imbalance payment or charge at a Load Zone.

Otherwise

$$\textbf{NMSAMTTOT}_{gsc} = \sum_{b} (\textbf{RTRMPR}_{b} * \textbf{MEB}_{gsc,\,b})$$

Where the price for Settlement Meter is determined as follows**:**

For EBNRT $_{b}$ <=0

$$\textbf{RTRMPR}_{b} = \sum_{y} (\textbf{RTLMP}_{b,\,y} * \textbf{TLMP}_{y}) / \sum_{y} \textbf{TLMP}_{y}$$

Otherwise RTRMPR $_{b}$ is determined as follows.

$$\textbf{RTRMPR}_{b} = \sum_{y} (\textbf{RNWF}_{b,\,y} * \textbf{RTLMP}_{b,\,y})$$

Where the weighting factor for the bus associated with the meter is:

$$\textbf{RNWF}_{b,y} = [\textbf{Max}(0.001, \sum_{r} \textbf{BP}_{y}) * \textbf{TLMP}_{y}] / [\sum_{y} \textbf{Max}(0.001, \sum_{r} \textbf{BP}_{r,y}) * \textbf{TLMP}_{y}].$$

The summation is over all Resources *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of thegeneration site code, *gsc*.

The above variables are defined as follows:

Variable	Unit	Description
$NMRTETOT_{gsc}$	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters *me* included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
$NMSAMTTOT_{gsc}$	$	*Net Metering Settlement Payment*—The total payment to the entire facility with a net metering arrangement.
$RTRMPR_{b}$	$/MWh	*Real-Time Price for the Energy Metered for each resource meter at bus*—The Real-Time Price for the Settlement Meter at Electrical Bus *b*, for the 15-minute Settlement Interval.
$EBNRT_{me}$	MWh	*Energy at bus Near Real Time*—The energy at the bus associated with the Settlement Meter gathered by the ERCOT Real-Time process for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy consumed. This is the integrated value for the 15 minute interval that is available shortly after the end of the 15 minute interval.
$MEB_{gsc, b}$	MWh	*Metered Energy at bus*—The metered energy by the Settlement Meter *me* for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy consumed.
$RTLMP_{b, y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
$RNWF_{b, y}$	none	*Net meter Weighting Factor per interval* —The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
$BP_{r, y}$	MW	*Base Point per Resource per interval* —The Base Point of Resource ID *id*, for the SCED interval *y*.
gsc	none	A generation site code.
r	none	A Generation Resource that is located at the facility with net metering. The summation is over all the Generation Resources at the facility.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

(4) The Generation Resource SCADA Splitting Percentage for each resource within a net metering arrangement for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{GSPLITPER}_{q,\ r,\ gsc,\ p} = \textbf{GSSPLITSCA}_{r} / \sum_{r} \textbf{GSSPLITSCA}_{r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$GSPLITPER_{q, r, gsc, p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. GSPLITPER is calculated by taking the SCADA values (GSSPLITSCA) for a particular Generation Resource *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval.
$GSSPLITSCA_{r}$	MWh	*Generation Resource SCADA Net Real Power provided via Telemetry*—The net real power provided via telemetry per Resource within the net metering arrangement, integrated for the 15-minute Settlement Interval.
gsc	none	A generation site code
r	none	A Generation Resource that is located at the facility with net metering. The summation is over all the Generation Resources at the facility.
q	none	A QSE.
p	none	A Resource Node Settlement Point.

(5) The total net payments and charges to each QSE for Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTEIAMTQSETOT}_{q} = \sum_{p} \textbf{RTEIAMT}_{q,\ p}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RTEIAMTQSETOT_{q}$	\$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance at all Resource Node Settlement Points for the 15-minute Settlement Interval.
$RTEIAMT_{q, p}$	\$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for the Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.

6.6.3.2 Real-Time Energy Imbalance Payment or Charge at a Load Zone

(1) The payment or charge to each QSE for Energy Imbalance Service is calculated based on the Real-Time SPP for the following amounts at a particular Load Zone Settlement Point:

(a) The amount of its Self-Schedules with sink specified at the Settlement Point; plus

(b) The amount of its Energy Bids cleared in the DAM at the Settlement Point; plus

(c) The amount of its Energy Trades at the Settlement Point where the QSE is the buyer; minus

(d) The amount of its Self-Schedules with source specified at the Settlement Point; minus

(e) The amount of its Energy Offers cleared in the DAM at the Settlement Point; minus

(f) The amount of its Energy Trades at the Settlement Point where the QSE is the seller; minus

(g) Its Adjusted Metered Load at the Settlement Point; plus

(h) The aggregated generation of its Non-Modeled Generators in the Load Zone.

(2) The payment or charge to each QSE for Energy Imbalance Service at a Load Zone for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEIAMT}_{q,\,p} = (-1) * \mathbf{RTSPP}_{p} * \Big\{(\mathbf{SSSK}_{q,\,p} * ¼) + (\mathbf{DAEP}_{q,\,p} * ¼) + (\mathbf{RTQQEP}_{q,\,p} * ¼) - (\mathbf{SSSR}_{q,\,p} * ¼) - (\mathbf{DAES}_{q,\,p} * ¼) - (\mathbf{RTQQES}_{q,\,p} * ¼) - \mathbf{RTAML}_{q,\,p} + \mathbf{RTMGNM}_{q,\,p}\Big\}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTEIAMT_{q,\,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for the Real-Time Energy Imbalance at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTAML_{q,\,p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the Adjusted Metered Load at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval.
$SSSK_{q,\,p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
$DAEP_{q,\,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
$RTQQEP_{q,\,p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount

Variable	Unit	Description
		of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSR $_{q,\,p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
DAES $_{q,\,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s Energy Offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q,\,p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
RTMGNM $_{q,\,p}$	MWh	*Real-Time Metered Generation from Non-Modeled generators per QSE per Settlement Point*—The total Real-Time energy produced by Non-Modeled Generators represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

(3) The total net payments and charges to each QSE for Energy Imbalance Service at all Load Zones for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEIAMTQSETOT}_{\,q} = \sum_{p} \mathbf{RTEIAMT}_{\,q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTEIAMTQSETOT $_{q}$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance at all Load Zone Settlement Points for the 15-minute Settlement Interval.
RTEIAMT $_{q,\,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The charge to QSE *q* for the Real-Time Energy Imbalance at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

6.6.3.3 Real-Time Energy Imbalance Payment or Charge at a Hub

(1) The payment or charge to each QSE for Energy Imbalance Service is calculated based on the Real-Time SPP for the following amounts at a particular Hub Settlement Point:

(a) The amount of its Self-Schedules with sink specified at the Settlement Point; plus

(b) The amount of its Energy Bids cleared in the DAM at the Settlement Point; plus

(c) The amount of its Energy Trades at the Settlement Point where the QSE is the buyer; minus

(d) The amount of its Self-Schedules with source specified at the Settlement Point; minus

(e) The amount of its Energy Offers cleared in the DAM at the Settlement Point; minus

(f) The amount of its Energy Trades at the Settlement Point where the QSE is the seller.

(2) The payment or charge to each QSE for Energy Imbalance Service at a Hub for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTEIAMT}_{q,p} = (-1) * \textbf{RTSPP}_{p} * \{ (\textbf{SSSK}_{q,p} * 1/4) + (\textbf{DAEP}_{q,p} * 1/4) + (\textbf{RTQQEP}_{q,p} * 1/4) - (\textbf{SSSR}_{q,p} * 1/4) - (\textbf{DAES}_{q,p} * 1/4) - (\textbf{RTQQES}_{q,p} * 1/4) \}$$

The above variables are defined as follows:

Variable	Unit	Description
RTEIAMT $_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for the Real-Time Energy Imbalance at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSK $_{q,p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
DAEP $_{q,p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s Energy Bids at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q,p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSR $_{q,p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
DAES $_{q,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s Energy Offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q,p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Hub Settlement Point.

(3) The total net payments and charges to each QSE for Energy Imbalance Service at all Hubs for the 15-minute Settlement Interval is calculated as follows:

$$\text{RTEIAMTQSETOT}_{q} = \sum_{p} \text{RTEIAMT}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RTEIAMTQSETOT_{q}$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance at all Hub Settlement Points for the 15-minute Settlement Interval.
$RTEIAMT_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The charge to QSE *q* for the Real-Time Energy Imbalance at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Hub Settlement Point.

6.6.3.4 Real-Time Energy Payment for DC Tie Import

(1) The payment to each QSE for energy imported into the ERCOT System through each DC Tie is calculated based on the Real-Time SPP at the DC Tie Settlement Point. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTDCIMPAMT}_{q,p} = \mathbf{(-1) * RTSPP}_{p} \mathbf{* (RTDCIMP}_{q,p} \mathbf{* 1/4)}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTDCIMPAMT_{q,p}$	$	*Real-Time DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTDCIMP_{q,p}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(2) ERCOT shall pay each QSE for energy imported into the ERCOT System during a declared Emergency Condition through each DC Tie in response to an ERCOT Dispatch Instruction. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEDCIMPAMT}_{q,p} = \mathbf{(-1) * Max \{RTSPP}_{p}\mathbf{, (VCOSTEMGENERGY}_{q} \mathbf{*} \boldsymbol{CA)}\mathbf{\}* (RTEDCIMP}_{q,p} \mathbf{* 1/4)}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTEDCIMPAMT_{q,p}$	$	*Real-Time Emergency DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for emergency DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.

FIP	\$/MMBtu	*Fuel Index Price*—As defined in Section 2, Definitions and Acronyms.
RTEDCIMP $_{q,\,p}$	MW	*Real-Time Emergency DC Import per QSE per Settlement Point*—The aggregated DC Tie Schedule for emergency energy imported by QSE *q* into the ERCOT System during Emergency Conditions through DC Tie *p*, for the 15-minute Settlement Interval.
VCOSTEMGENERGY$_q$	\$/MWh	*Verified Cost for Emergency Energy*—The ERCOT verified cost for the energy imported by QSE *q* into the ERCOT System during declared Emergency Condition through a DC Tie *p* as instructed by an ERCOT dispatch instruction.
CA	#	*Cost Adder*—A multiplier of 1.10.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(3) The total of the payments to each QSE for all energy imported into the ERCOT System through DC Ties for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCIMPAMTQSETOT}_{q} = \sum_{p} (\textbf{RTDCIMPAMT}_{q,\,p} + \textbf{RTEDCIMPAMT}_{q,\,p})$$

The above variables are defined as follows:

Variable	Unit	Definition
RTDCIMPAMTQSETOT $_q$	\$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy imported into the ERCOT System through DC Ties for the 15-minute Settlement Interval.
RTDCIMPAMT $_{q,\,p}$	\$	*Real-Time DC Import Amount per QSE per Settlement Point*—The payment to QSE *q* for DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
RTEDCIMPAMT $_{q,\,p}$	\$	*Real-Time Emergency DC Import Amount per QSE per Settlement Point* – The payment to QSE *q* for emergency DC Tie import through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

6.6.3.5 Real-Time Payment for a Block Load Transfer Point

(1) ERCOT shall pay each QSE for the energy delivered to an ERCOT Load through a Block Load Transfer (BLT) Point that is moved in response to an ERCOT Verbal Dispatch Instruction (VDI) during a declared Emergency Condition, from the ERCOT Control Area to a non-ERCOT Control Area. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{BLTRAMT}_{q,\,bltp,\,p} = \textbf{(-1) * MAX \{RTSPP}_{p}\textbf{, (VCOSTEMGENERGY}_{q,\,bltp}\textbf{)*}\textbf{\textit{CA}}\textbf{\} * BLTR}_{q,\,bltp,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition

BLTRAMT $_{q, bltp, p}$	$	*Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point* – The payment to QSE *q* for the BLT Resource that delivers energy to Load Zone *p* through BLT Point *bltp*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point* – The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
VCOSTEMGENERGY $_{q, bltp}$	$/MWh	*Verified Cost for Emergency Energy* – The ERCOT verified cost for the energy delivered to an ERCOT Load through BLT Point *bltp* during a declared Emergency Condition in ERCOT as determined by an ERCOT VDI.
CA	#	*Cost Adder* – A multiplier of 1.10.
BLTR $_{q, p, bltp}$	MWh	*Block Load Transfer Resource per QSE per Settlement Point per BLT Point* – The energy delivered to an ERCOT Load in Load Zone *p* through BLT Point *bltp* represented by QSE *q*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.

(2) The total of the payments to each QSE for all energy delivered to ERCOT Loads through BLT Points for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{BLTRAMTQSETOT}_{\boldsymbol{q}} = \sum_{p} \sum_{bltp} \textbf{BLTRAMT}_{\boldsymbol{q}, blt, p, \boldsymbol{p}}$$

The above variables are defined as follows:

Variable	Unit	Definition
BLTRAMTQSETOT $_{q}$	$	*Block Load Transfer Resource Amount QSE Total per QSE* —The total of the payments to QSE *q* for energy delivered into the ERCOT System through BLT Points for the 15-minute Settlement Interval.
BLTRAMT $_{q, bltp, p}$	$	*Block Load Transfer Resource Amount per QSE per Settlement Point per BLT Point*—The payment to QSE *q* for the BLT Resource at BLT Point *bltp*, which delivers energy to Load Zone *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.
bltp	none	A BLT Point.

6.6.3.6 Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption

(1) The charge to a QSE that is exporting energy from the ERCOT System under the "Oklaunion Exemption" through a DC Tie associated with the exemption is calculated based on the Real-Time SPP at the DC Tie Settlement Point. This charge for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCEXPAMT}_{\boldsymbol{q, p}} = \textbf{RTSPP}_{\boldsymbol{p}} * (\textbf{RTDCEXP}_{\boldsymbol{q, p}} * \tfrac{1}{4})$$

The above variables are defined as follows:

Variable	Unit	Definition

RTDCEXPAMT $_{q, p}$	$	*Real-Time DC Export Amount per QSE per Settlement Point*—The charge to QSE *q* for the DC Tie exports through DC Tie *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
RTDCEXP $_{q, p}$	MW	*Real-Time DC Export per QSE per Settlement Point*—The aggregated DC Tie Schedule through DC Tie *p* submitted by QSE *q* that is under the "Oklaunion Exemption" as an exporter from the ERCOT area, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

(2) The total of the charges to each QSE for all energy exported from the ERCOT System through DC Ties for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTDCEXPAMTQSETOT}_{q} = \sum_{p} \textbf{RTDCEXPAMT}_{q, p}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTDCEXPAMTQSETOT $_{q}$	$	*Real-Time DC Export Amount QSE Total per QSE*—The total of the charges to QSE *q* for energy exported from the ERCOT System through DC Ties for the 15-minute Settlement Interval.
RTDCEXPAMT $_{q, p}$	$	*Real-Time DC Export Amount per QSE per Settlement Point*—The charge to QSE *q* for the DC Tie exports through DC Tie *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A DC Tie Settlement Point.

6.6.4 Real-Time Congestion Payment or Charge for Self-Schedules

(1) The congestion payment or charge to each QSE submitting a Self-Schedule calculated based on the difference in Real-Time SPPs at the specified sink and the source of the Self-Schedule multiplied by the amount of the Self-Schedule. The congestion charge to each QSE for each of its Self-Schedule for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTCCAMT}_{q, s} = (\textbf{RTSPP}_{sink, s} - \textbf{RTSPP}_{source, s}) * (\textbf{SSQ}_{q, s} * 1/4)$$

The above variables are defined as follows:

Variable	Unit	Description
RTCCAMT $_{q, s}$	$	*Real-Time Congestion Cost Amount per QSE per Self-Schedule*—The congestion charge to QSE *q* for its Self-Schedule *s*, for the 15-minute Settlement Interval.
RTSPP $_{sink, s}$	$/MWh	*Real-Time Settlement Point Price at the Sink of Self-Schedule*—The Real-Time SPP at the sink of the Self-Schedule *s*, for the 15-minute Settlement Interval.
RTSPP $_{source, s}$	$/MWh	*Real-Time Settlement Point Price at the Source of Self-Schedule*—The Real-Time SPP at the source of the Self-Schedule *s*, for the 15-minute Settlement Interval.
SSQ $_{q,s}$	MW	*Self-Schedule Quantity per Self-Schedule*—The QSE *q*'s Self Schedule MW quantity for

		Self-Schedule *s*, for the 15-minute Settlement Interval.
q	none	A QSE.
s	none	A Self-Schedule.
sink	none	Sink Settlement Point
source	none	Source Settlement Point

(2) The total net congestion payments and charges to each QSE for all its Self-Schedules for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTCCAMTQSETOT}_{q} = \sum_{s} \textbf{RTCCAMT}_{q,\,s}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTCCAMTQSETOT $_{q}$	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
RTCCAMT $_{q, s}$	$	*Real-Time Congestion Cost Amount per QSE per Self-Schedule*—The congestion payment or charge to QSE *q* for its Self-Schedule *s*, for the 15-minute Settlement Interval.
q	none	A QSE.
s	none	A Self-Schedule.

6.6.5 Generation Resource Base-Point Deviation Charge

A QSE for a Generation Resource shall pay a Base-Point deviation charge if the Resource did not follow Dispatch Instructions and Ancillary Services deployments within defined tolerances, except when the Dispatch Instructions and Ancillary Services deployments violate the Resource Parameters. The Base-Point deviation charge does not apply to Generation Resources between breaker close and the time at which the telemetered High Sustained Limit (HSL) becomes greater than Low Sustained Limit (LSL). The desired output from a Generation Resource during a 15-minute Settlement Interval is calculated as follows:

$$\textbf{AABP} = \sum_{y} ((\textbf{BP}_{y} + \textbf{BP}_{y-1})/2 * \textbf{TLMP}_{y}) \,/\, (\sum_{y} \textbf{TLMP}_{y}) + \textbf{TWAR}$$

Where :

$$\textbf{TWAR} = \sum_{y} ((\textbf{ARI}_{y} * \textbf{TLMP}_{y}) \,/\, (\sum_{y} \textbf{TLMP}_{y})$$

The above variables are defined as follows:

Variable	Unit	Definition
AABP	MW	*Adjusted Aggregated Base Point*—The Generation Resource's aggregated Base Point adjusted for Ancillary Service deployments, for the 15-minute Settlement Interval.
BP $_{y}$	MW	*Base Point by interval*—The Base Point for the Generation Resource at the Resource Node, for the SCED interval *y*.

TLMP $_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
TWAR	MW	*Time-Weighted Average Regulation* – The amount of regulation that the Generation Resource should have produced based on the deployment signals as calculated by the Load Frequency Control (LFC) within the 15-minute Settlement Interval.
ARI $_y$	MW	*Average Regulation Instruction* – The amount of regulation that the Generation Resource should have produced based on the deployment signals as calculated by the LFC within the SCED interval.
y	none	A SCED interval in the Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.

6.6.5.1 General Generation Resource Base-Point Deviation Charge

(1) Unless one of the exceptions specified in paragraphs (2) and (3) below applies, ERCOT shall charge a Generation Resource Base-Point deviation charge for a Generation Resource other than those described in Section 6.6.5.2, IRR Generation Resource Base-Point Deviation Charge, and Section 6.6.5.3, Generators Exempt from Deviation Charges, when:

(a) The SPP for the Resource Node is positive; and

(b) The telemetered generation of the Generation Resource over the 15-minute Settlement Interval is outside the tolerances defined later in this Subsection.

(2) ERCOT may not charge a QSE a Generation Resource Base-Point deviation charge under paragraph (1) above when both (a) and (b) apply:

(a) The generation deviation of the Generation Resource over the 15-minute Settlement Interval is in a direction that contributes to frequency corrections that resolve an ERCOT System frequency deviation; and

(b) The ERCOT System frequency deviation is greater than +/-0.05 Hz at any time during the 15-minute Settlement Interval.

(3) ERCOT may not charge a QSE a Generation Resource Base-Point deviation charge under paragraph (1) above for any 15-minute Settlement Interval during which Responsive Reserve is deployed.

6.6.5.1.1 Base Point Deviation Charge for Over Generation

(1) ERCOT shall charge a QSE for a Generation Resource for over generation that exceeds the following tolerance. The tolerance is the greater of:

(a) Five percent of the average of the Base Points in the Settlement Interval adjusted for any Ancillary Services deployments; or

(b) Five MW for metered generation above the average of the Base Points in the Settlement Interval adjusted for any Ancillary Services deployments.

(2) The charge to each QSE for over-generation of each Generation Resource at each Resource Node Settlement Point, if the Real-Time metered generation is greater than the upper tolerance during a given 15-minute Settlement Interval, is calculated as follows:

$$\textbf{BPDAMT}_{q, r, p} = \textbf{Max (0, RTSPP}_{p}\textbf{) * Max [0, (TWTG}_{q, r, p} \textbf{ – ¼ * Max (((1 + K1) * AABP}_{q, r, p}\textbf{), (AABP}_{q, r, p}\textbf{ + Q1)))]}$$

Where:

$$\textbf{TWTG}_{q, r, p} = \sum_{y} \textbf{(ATG}_{q, r, p, y} \textbf{ * TLMP}_{y} \textbf{ /3600)}$$

The above variables are defined as follows:

Variable	Unit	Definition
BPDAMT $_{q, r, p}$	$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
TWTG $_{q, r, p}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
AABP $_{q, r, p}$	MW	*Adjusted Aggregated Base Point per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments, of Generation Resource r represented by QSE q at Resource Node p, for the 15-minute Settlement Interval.
ATG $_{q, r, p, y}$	MW	*Average Telemetered Generation* - The average telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the SCED interval.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the 15-minute Settlement Interval.
K1	none	The percentage tolerance for over-generation, 5%.
Q1	MW	The MW tolerance for over-generation, 5 MW.
q	none	A QSE.
3600	none	The number of seconds in one hour.
p	none	A Resource Node Settlement Point.
r	none	A non-exempt, non- Intermittent Renewable Resources (IRR) Generation Resource.
y	none	An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval.

6.6.5.1.2 Base Point Deviation Charge for Under Generation

(1) ERCOT shall charge a QSE for a Generation Resource for under generation if the metered generation is below the lesser of:

(a) 95% of the average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments; or

(b) The average of the Base Points in the Settlement Interval adjusted for any Ancillary Service deployments minus 5 MW.

(2) The charge to each QSE for under-generation of each Generation Resource at each Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:

$$\text{BPDAMT}_{q, r, p} = \text{Max}(0, \text{RTSPP}_{p}) * \text{Min}(1, \text{KP}) * \text{Max}\{0, \{\text{Min}[((1 - \text{K2}) * ¼(\text{AABP}_{q, r, p})), ¼(\text{AABP}_{q, r, p} - \text{Q2})] - \text{TWTG}_{q, r, p}\}\}$$

The above variables are defined as follows:

Variable	Unit	Definition
BPDAMT $_{q, r, p}$	$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
TWTG $_{q, r, p}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
AABP $_{q, r, p}$	MW	*Adjusted Aggregated Base Point*—The aggregated Base Point adjusted for Ancillary Service deployments of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
KP	None	The coefficient applied to the SPP for under-generation charge, 1.0.
K2	None	The percentage tolerance for under-generation, 5%.
Q2	MW	The MW tolerance for under-generation, 5 MW.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A non-exempt, non-IRR Generation Resource.

6.6.5.2 IRR Generation Resource Base-Point Deviation Charge

(1) ERCOT shall charge a QSE for an IRR a Base-Point deviation charge if the IRR metered generation is more than 10% above its Adjusted Aggregated Base Point and if the Adjusted Aggregated Base Point is two MW or more below the IRR's HSL. The deviation charge may be refunded if the IRR shows, to ERCOT's satisfaction, that the IRR was taking the necessary control actions to produce at levels equal to or less than the Base Point but was unable to comply solely due to increasing renewable energy input. The IRR must always take the necessary control actions, in its capability, to comply with Base Point Dispatch Instructions if the Base Point is two MW or more below the IRR's HSL as soon as practicable.

(2) The charge to each QSE for non-excused over-generation of each IRR at each Resource Node Settlement Point, if the Real-Time metered generation is greater than the upper tolerance during a 15-minute Settlement Interval, is calculated as follows:

If AABP $_{q, r, p}$ > (HSL $_{q, r, p}$ – QIRR)

$$\mathbf{BPDAMT}_{q,r,p} = \mathbf{0}$$

Otherwise

$$\mathbf{BPDAMT}_{q,r,p} = \mathbf{Max\ (0,\ RTSPP}_{p}\mathbf{)\ *}$$
$$\mathbf{Max\ (0,\ TWTG}_{q,r,p} - \mathbf{\tfrac{1}{4}\ *AABP}_{q,r,p}\mathbf{\ *\ (1 + KIRR))}$$

The above variables are defined as follows:

Variable	Unit	Definition

$BPDAMT_{q, r, p}$	\$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval.
$RTSPP_{p}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Resource Node *p*, for the 15-minute Settlement Interval.
$TWTG_{q, r, p}$	MWh	*Time-Weighted Telemetered Generation per QSE per Settlement Point per Resource*—The telemetered generation of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
$AABP_{q, r, p}$	MW	*Adjusted Aggregated Base Point Generation per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments, of Generation Resource *r* represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
$HSL_{q, r, p}$	MW	*High Sustainable Limit Generation per QSE per Settlement Point per Resource*—The HSL of Generation Resource r represented by QSE q at Resource Node p for the hour that includes the 15-minute Settlement Interval.
KIRR		The percentage tolerance for over-generation of an IRR, 10%.
QIRR	MW	The threshold to test the adjusted aggregated Base Point against the HSL for an IRR, 2 MW.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	An IRR.

6.6.5.3 Generators Exempt from Deviation Charges

Generation Resource Base Point deviation charges do not apply to RMR Units, Dynamically Scheduled Resources (except as described in Section 6.4.2.2, Output Schedules for Dynamically Scheduled Resources), or Qualifying Facilities (QFs) that do not submit an Energy Offer Curve for the Settlement Interval.

6.6.5.4 Base Point Deviation Payment

ERCOT shall pay the Base-Point deviation charges collected from the QSEs representing Generation Resources to the QSEs representing Load based on LRS. The payment to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LABPDAMT}_{q} = \quad \mathbf{(-1) * BPDAMTTOT * LRS}_{q}$$

Where:

$$\text{BPDAMTTOT} = \sum_{q} \text{BPDAMTQSETOT}_{q}$$

$$\text{BPDAMTQSETOT}_{q} = \sum_{p} \sum_{r} \text{BPDAMT}_{q, r, p}$$

The above variables are defined as follows:

Variable	Unit	Definition

LABPDAMT $_q$	$	*Load-Allocated Base-Point Deviation Amount per QSE*—QSE *q*'s share of the total charge for all the Generation Resource's Base Point deviation, based on LRS for the 15-minute Settlement Interval.
BPDAMTTOT	$	*Base-Point Deviation Amount Total*—The total of Base-Point Deviation Charges to all QSEs for all Generation Resources, for the 15-minute Settlement Interval.
BPDAMTQSETOT $_q$	$	*Base-Point Deviation Amount QSE Total per QSE*—The total of Base-Point Deviation Charges to QSE *q* for all Generation Resources represented by this QSE, for the 15-minute Settlement Interval.
BPDAMT $_{q, r, p}$	$	*Base Point Deviation Charge per QSE per Settlement Point per Resource*—The charge to QSE *q* for Generation Resource *r* at Resource Node *p*, for its deviation from Base Point, for the 15-minute Settlement Interval.
LRS $_q$	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource.

6.6.6 Reliability Must-Run Settlement

6.6.6.1 RMR Standby Payment

(1) The Standby Payment for Reliability Must-Run (RMR) Service is paid to each QSE representing an RMR Unit for each RMR Unit for each contracted hour under performance requirements set forth in Section 22, Attachment B, Standard Form Reliability Must-Run Agreement, and other performance requirements in these Protocols. For Initial Settlement, the Standby Payment is the "Estimated Standby Cost" stated in the RMR Agreement. For Final and True-Up Settlements, the Standby Payment is based on the RMR Unit's actual Eligible Cost.

(2) The Standby Payment to each QSE for each RMR Unit for each hour is calculated as follows:

$$\textbf{RMRSBAMT}_{\boldsymbol{q, r}} \quad = \quad \textbf{(-1) * RMRSBPR}_{\boldsymbol{q, r}}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
RMRSBAMT $_{q, r}$	$	*Reliability Must Run Standby Payment per QSE per Resource by hour*—The Standby Payment to QSE *q* for RMR Unit *r*, for the hour.
RMRSBPR $_{q, r}$	$ per hour	*Reliability Must Run Standby Price per QSE per Resource by hour*—The hourly standby cost for RMR Unit *r* represented by QSE *q*, for the hour. See item (3) below.
q	none	A QSE.
r	none	An RMR Unit.

(3) For the Initial Settlement and resettlements executed before true-up and before actual cost data is submitted, the standby price of an RMR Unit is the "Estimated Standby Cost"

stated in the RMR Agreement. For other resettlements, the standby price of an RMR Unit for each hour is calculated as follows:

$$\mathbf{RMRSBPR}_{q,r} = \mathbf{RMRMNFC}_{q,r} \,/\, \mathbf{MH}_{q,r} * (1 + \mathbf{RMRIF} * \mathbf{RMRCRF}_{q,r} * \mathbf{RMRARF}_{q,r})$$

Where:

RMR Capacity Reduction Factor

If ($RMRTCAPA_{q,r} + RMRTCAP_{q,r} \geq RMRCCAP_{q,r}$) then, $RMRCRF_{q,r} = 1$

Otherwise

$$RMRCRF_{q,r} = \text{Max}\,(0, 1 - 2 * (RMRCCAP_{q,r} - RMRTCAP_{q,r}) \,/\, RMRCCAP_{q,r})$$

RMR Availability Reduction Factor

If ($RMRHREAF_{q,r} \geq RMRTA_{q,r}$) then, $RMRARF_{q,r} = 1$

Otherwise

$$RMRARF_{q,r} = \text{Max}\,(0, 1 - (RMRTA_{q,r} - RMRHREAF_{q,r}) * 2)$$

RMR Hourly Rolling Equivalent Availability Factor

If ($RMREH_{q,r} < 4380$)

$$RMRHREAF_{q,r} = 1$$

Otherwise

$$RMRHREAF_{q,r} = \left(\sum_{hr=h-4379}^{h} RMRAFLAG_{q,r,hr}\right) / 4380$$

The above variables are defined as follows:

Variable	Unit	Definition
$RMRSBPR_{q,r}$	\$ per hour	*Reliability Must Run Standby Price per QSE per Resource by hour*—The Standby Price for RMR Unit *r* represented by QSE *q* for the hour.
$RMRARF_{q,r}$	none	*Reliability Must Run Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor of RMR Unit *r* represented by QSE *q*, for the hour.
$RMRCRF_{q,r}$	none	*Reliability Must Run Capacity Reduction Factor per QSE per Resource by hour*—The capacity reduction factor of the RMR Unit, for the hour. See paragraph (2) of Section 3.14.1.13, Incentive Factor
$RMRCCAP_{q,r}$	MW	*Reliability Must Run Contractual Capacity per QSE per Resource*—The capacity of RMR Unit *r* represented by QSE *q* as specified in the RMR Agreement.
$RMRTCAP_{q,r}$	MW	*Reliability Must Run Testing Capacity by hour*—The testing capacity of RMR Unit *r* represented by QSE *q*, for the hour.
$RMRTA_{q,r}$	none	*Reliability Must Run Target Availability per QSE per Resource*—The Target Availability of RMR Unit *r* represented by QSE *q*, as specified in the RMR Agreement and divided by 100 to convert a percentage to a fraction.
$RMRHREAF_{q,r}$	none	*Reliability Must Run Hourly Rolling Equivalent Availability Factor per QSE per Resource by hour*—The equivalent availability factor of RMR Unit *r* represented by QSE *q* over 4380 hours, for the hour.

Variable	Unit	Definition
RMREH $_{q, r}$	none	*Reliability Must Run Elapsed number of Hours per QSE per Resource by hour*—The number of the elapsed hours of the term of the RMR Agreement for RMR Unit *r* represented by QSE *q*, for the hou.
RMRMNFC $_{q, r}$	$	*Reliability Must Run Monthly Non-Fuel Cost per QSE per Resource*—The actual non-fuel Eligible Cost of RMR Unit *r* represented by QSE *q*, for the month.
MH $_{q, r}$	hour	*Number of Hours in the Month per QSE per Resource*—The total number of hours of the month, when RMR Unit *r* represented by QSE *q* is under an RMR Agreement.
RMRIF	none	*Reliability Must Run Incentive Factor*—The Incentive Factor of RMR Units under RMR Agreement.
RMRARF $_{q, r}$	none	*Reliability Must Run Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor of RMR Unit *r* represented by QSE *q*, as calculated for the hour.
RMRAFLAG $_{q, r, hr}$	none	*RMR Availability Flag per QSE per Resource by hour*—The flag of the availability of RMR Resource *r* represented by QSE *q*, 1 for available and 0 for unavailable, for the hour.
RMRTCAPA $_{q, r}$	MW	*Reliability Must Run Testing Capacity Adjustment by hour*—The testing capacity adjustment factor, in the event an ERCOT Operator has deemed that a RMR Unit's Tested Capacity did not materially affect the reliability of the ERCOT System, of an RMR Unit *r* represented by QSE *q*, for the hour. See paragraph (2) of Section 3.14.1.13.
q	none	A QSE.
r	none	An RMR Unit.
hr	none	The index for a given hour and all the previous 4379 hours.
4380	none	The number of hours in a six-month period.

(4) The total of the Standby Payments to each QSE for all RMR Units represented by this QSE for a given hour is calculated as follows:

$$\textbf{RMRSBAMTQSETOT}_{q} = \sum_{r} \textbf{RMRSBAMT}_{q,\, r}$$

The above variables are defined as follows:

Variable	Unit	Definition
RMRSBAMTQSETOT $_{q}$	$	*Reliability Must Run Standby Amount QSE Total per QSE*—The total of the Standby Payments to QSE *q* for all RMR Units represented by this QSE for the hour.
RMRSBAMT $_{q, r}$	$	*Reliability Must Run Standby Payment per QSE per Resource*—The Standby Payment to QSE *q* for RMR Unit *r*, for the hour.
q	none	A QSE.
r	none	An RMR Unit.

6.6.6.2 RMR Payment for Energy

(1) Payment for energy on the Initial Settlement and settlements executed before True-up and before actual cost data is submitted must be calculated using the estimated input/output curve and startup fuel as specified in the RMR Agreement, the actual energy produced

and the Fuel Index Price (FIP). The payment for energy for all other settlements must be based on actual fuel costs for the RMR Unit. The payment for energy for each hour is calculated as follows:

$$\textbf{RMREAMT}_{q,r} = (-1) * ((\textbf{FIP} + \textbf{RMRCEFA}_{q,r}) * \textbf{RMRSUFQ}_{q,r} / \textbf{RMRH}_{q,r}) * \textbf{RMRALLOCFLAG}_{q,r} + \sum_{i=1}^{4} (((\textbf{FIP} + \textbf{RMRCEFA}_{q,r}) * \textbf{RMRHR}_{q,r,i} + \textbf{RMRVCC}_{q,r}) * \textbf{RTMG}_{q,r,i})$$

The above variables are defined as follows:

Variable	Unit	Definition
RMREAMT $_{q,\ r}$	$	*Reliability Must Run Energy Amount per QSE per Resource by hour*—The energy payment to QSE *q* for RMR Unit *r*, for the hour.
FIP	$/MMBtu	*Fuel Index Price*—The FIP for the Operating Day.
RMRSUFQ $_{q,\ r}$	MMBtu	*Reliability Must Run Startup Fuel Quantity per QSE per Resource*—The Estimated Startup Fuel specified in the RMR Agreement for RMR Unit *r* represented by QSE *q*.
RMRH $_{q,\ r,h}$	hour	*Reliability Must Run Hours*—The number of hours during which RMR Unit *r* represented by QSE *q* is instructed On-Line for the Operating Day.
RMRALLOCFLAG $_{q,\ r}$	none	*Reliability Must Run Startup Flag per QSE per Resource by hour*—The number that indicates whether or not the startup fuel cost of RMR Unit *r* represented by QSE *q* is allocated to the hour. The startup fuel cost will be allocated equally to all contiguous intervals for which there is an eligible start. The RMRALLOCFLAG $_{q,r}$ value is 1 if the startup fuel cost is allocated; otherwise, its value is 0. The RMRALLOCFLAG $_{q,\ r}$ for eligibility is determined in Protocol Sections 5.6.2, RUC Startup Cost Eligibility, and 5.6.3, Forced Outage of a RUC-Committed Resource, for start-up payments and commitments in either the Reliability Unit Commitment (RUC) or DAM markets.
RMRHR $_{q,\ r,\ i}$	MMBtu/MWh	*Reliability Must Run Heat Rate per QSE per Resource by Settlement Interval by hour*—The multiplier determined based on the input/output curve and the Real-Time generation of RMR Unit *r* represented by QSE *q*, for the 15-minute Settlement Interval *i* in the hour.
RMRVCC $_{q,\ r}$	$/MWh	*Reliability Must Run Variable Cost Component per QSE per Resource*—The monthly cost component that is used to adjust the energy cost calculation to reflect the actual fuel costs of RMR Unit *r* represented by QSE *q*. The value is initially set to zero. For resettlements, see item (2) below.
RTMG $_{q,\ r,\ i,}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval by hour*— The Real-Time energy from RMR Unit *r* represented by QSE *q*, for the 15-minute Settlement Interval *i in the hour h*.
RMRCEFA $_{q,\ r}$	$/MMBtu	*Reliability Must Run Contractual Estimated Fuel Adder*—The Estimated Fuel Adder that is contractually agreed upon in Section 22F, Attachment B, Standard Form Reliability Must-Run Agreement.
q	none	A QSE.
r	none	An RMR Unit.
i	none	A 15-minute Settlement Interval.

(2) If the RMR actual fuel cost is filed in accordance with the timeline in these Protocols, the monthly RMR variable cost component is calculated for the subsequent resettlements as follows:

$$\mathbf{RMRVCC}_{q,r} = (\mathbf{RMRMFCOST}_{q,r} + \sum_{h} \mathbf{RMREAMT}_{q,r,f,h}) / (\sum_{i} \mathbf{RTMG}_{q,r,i})$$

The above variables are defined as follows:

Variable	Unit	Definition
$RMRVCC_{q,r}$	$/MWh	*Reliability Must Run Variable Cost Component per QSE per Resource*—The monthly cost component that is used to adjust the energy cost calculation to reflect the actual fuel costs of RMR Unit *r* represented by QSE *q*.
$RMRMFCOST_{q,r}$	$	*Reliability Must Run Monthly actual Fuel Cost per QSE per Resource*—The monthly actual fuel cost of RMR Unit *r* represented by QSE *q*, for the month.
$RTMG_{q,r,i}$	MWh	*Real-Time Metered Generation per QSE per Resource by Settlement Interval*—The Real-Time energy from RMR Unit *r* represented by QSE *q* for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	An RMR Unit.
h	none	An hour in the month.
i	none	A 15-minute Settlement Interval in the month.
$RMREAMT_{q,r,f,h}$	$	*Reliability Must Run Energy Amount per QSE per Resource by hour*—The energy payment to QSE q for RMR Unit r, for the hour h from the former Settlement Statement f.
f	none	Amount from former settlement run.

(3) The total of the payments for energy to each QSE for all RMR Units represented by this QSE for a given hour is calculated as follows:

$$\mathbf{RMREAMTQSETOT}_{q} = \sum_{r} \mathbf{RMREAMT}_{q,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RMREAMTQSETOT_{q}$	$	*Reliability Must Run Energy Amount QSE Total per QSE*—The total of the energy payments to QSE *q* for all RMR Units represented by this QSE for the hour.
$RMREAMT_{q,r}$	$	*Reliability Must Run Energy Amount per QSE per Resource by hour*—The energy payment to QSE *q* for RMR Unit *r*, for the hour.
q	none	A QSE.
r	none	An RMR Unit.

6.6.6.3 RMR Adjustment Charge

(1) Each QSE that represents an RMR Unit shall pay a charge designed to recover the net total revenues from RUC settlements, and from Real-Time settlements received by that QSE for all RMR Units that it represents, except that the charge does not include net revenues received by the QSE for the RMR standby payments calculated under Section 6.6.6.1, RMR Standby Payment, and the RMR energy payments calculated under Section 6.6.6.2, RMR Payment for Energy.

(2) The charge for each QSE representing an RMR Unit for a given Operating Hour is calculated as follows:

$$\mathbf{RMRAAMT}_{q} = (-1) * [\sum_{p} \sum_{r} (((-1) * \sum_{i=1}^{4} (\mathbf{RTMG}_{q,r,p,i} * \mathbf{RTSPP}_{p,i})) + \sum_{i=1}^{4} \mathbf{EMREAMT}_{q,r,p,i} + \mathbf{RUCMWAMT}_{q,r,p} + \mathbf{RUCCBAMT}_{q,r,p} + \mathbf{RUCDCAMT}_{q,r,p} + \sum_{i=1}^{4} \mathbf{VSSEAMT}_{q,r,p,i} + \sum_{i=1}^{4} \mathbf{VSSVARAMT}_{q,r,i})]$$

The above variables are defined as follows:

Variable	Unit	Definition
$RMRAAMT_{q}$	$	*RMR Adjustment Charge per QSE*—The adjustment from QSE *q* standby payments and energy payments for all RMR Units represented by this QSE, for the revenues received for the same RMR Units from RUC and Real-Time Operations, for the hour..
$RTEIAMT_{q, p, i}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for the Real-Time Energy Imbalance at Settlement Point *p*, for the 15-minute Settlement Interval.
$EMREAMT_{q, r, p, i}$	$	*Emergency Energy Amount per QSE per Settlement Point per unit per interval*—The payment to QSE q for the additional energy produced by RMR Unit r at Resource Node p in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval *i*.
$RUCMWAMT_{q, r, p}$	$	*RUC Make-Whole Amount per QSE per Settlement Point per unit*—The amount calculated for RMR Unit *r* committed in RUC at Resource Node *p* to make whole the startup and minimum energy cost of this unit, for the hour. See Section 5.7.1, RUC Make-Whole Payment.
$RUCCBAMT_{q, r}$	$	*RUC Clawback Charge per QSE per unit*—The RUC Clawback Charge to QSE *q* for RMR Unit *r*, for the hour. See Section 5.7.2, RUC Clawback Charge.
$RUCDCAMT_{q, r, p}$	$	*RUC Decommitment Amount per QSE per Settlement Point per unit*—The amount calculated for RMR Unit *r* at Resource Node *p* represented by QSE *q* due to ERCOT de-commitment, for the hour.
$VSSEAMT_{q, r, p, i}$	$	*Voltage Support Service Energy Amount per QSE per Settlement Point per unit per interval* —The compensation to QSE *q* for ERCOT-directed power reduction from RMR Unit *r* at Resource Node *p* to provide VSS, for the 15-minute Settlement Interval *i*.
$VSSVARAMT_{q, r, i}$	$	*Voltage Support Service var Amount per QSE per Unit*—The payment to QSE *q* for the Voltage Support Service (VSS) provided by RMR Unit r, for the 15-minute Settlement Interval *i*.
$RTSPP_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTMG_{q, r, p}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource r represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	An RMR Unit.
i	none	A 15-minute Settlement Interval in the hour.

6.6.6.4 RMR Charge for Unexcused Misconduct

(1) If a Misconduct Event, as defined in the RMR Agreement, is not excused as provided in the RMR Agreement, then ERCOT shall charge the QSE that represents the RMR Unit an unexcused misconduct amount of $10,000 for each unexcused Misconduct Event as follows:

$$\mathbf{RMRNPAMT}_{q, r} = \mathbf{\$10{,}000 * RMRNPFLAG}_{q,r}$$

The above variable is defined as follows:

Variable	Unit	Definition
$RMRNPAMT_{q, r}$	$	*Reliability Must Run Unexcused Misconduct Charge per QSE per Resource*—The charge to QSE *q* for the unexcused Misconduct Event of RMR Unit *r* for an Operating Day.
$RMRNPFLAG_{q, r}$	$	*Reliability Must Run Non-Performance Flag per QSE per Resource*—A flag for the QSE q for the unexcused Misconduct Event of RMR Unit r for an Operating Day.
q	none	A QSE.
r	none	An RMR Unit.

(2) The total of the charges to each QSE for unexcused Misconduct Events of all RMR Units represented by this QSE for a given Operating Day is calculated as follows:

$$\mathbf{RMRNPAMTQSETOT}_{q} = \sum_{r} \mathbf{RMRNPAMT}_{q, r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RMRNPAMTQSETOT_{q}$	$	*Reliability Must Run Unexcused Misconduct Amount QSE Total per QSE*—The total of the charges to QSE *q* for unexcused Misconduct Events of the RMR Units represented by this QSE for the Operating Day.
$RMRNPAMT_{q, r}$	$	*Reliability Must Run Unexcused Misconduct Charge per QSE per Resource*—The charge to QSE *q* for the unexcused Misconduct Event of RMR Unit *r* for the Operating Day.
q	none	A QSE.
r	none	An RMR Unit.

6.6.6.5 RMR Service Charge

The total RMR cost for all RMR Units less the amount received from DAM, RUC processes and Real-Time operations for all RMR Units is allocated to the QSEs representing loads based on LRS. The RMR Service charge to each QSE for a given hour is calculated as follows:

$$\begin{aligned}\mathbf{LARMRAMT}_{q} = \; & \mathbf{(-1) * (RMRSBAMTTOT + RMREAMTTOT} \\ & \mathbf{+ RMRAAMTTOT} - \sum_{i=1}^{4} \mathbf{RMRDAESRTVTOT}_{i} - \\ & \mathbf{(RMRDAEREVTOT + RMRDAMWREVTOT) +} \\ & \mathbf{RMRNPAMTTOT / H) * HLRS}_{q}\end{aligned}$$

Where:

RMR Standby Amount Total

$$\text{RMRSBAMTTOT} = \sum_{q} \text{RMRSBAMTQSETOT}_{q}$$

RMR Energy Amount Total

$$\text{RMREAMTTOT} = \sum_{q} \text{RMREAMTQSETOT}_{q}$$

RMR Adjustment Charge Total

$$\text{RMRAAMTTOT} = \sum_{q} \text{RMRAAMT}_{q}$$

RMR Non-Performance Amount Total

$$\text{RMRNPAMTTOT} = \sum_{q} \text{RMRNPAMTQSETOT}_{q}$$

Total Day-Ahead energy revenue for all RMR Units

$$\text{RMRDAEREVTOT} = \sum_{q} \sum_{r} \sum_{p} \text{DAEREV}_{q, r, p}$$

$$\text{DAEREV}_{q, r, p} = (-1) * \text{DASPP}_{p} * \text{DAESR}_{q, r, p}$$

Total Real-Time value of Day-Ahead energy for all RMR Units by interval

$$\text{RMRDAESRTVTOT}_{i} = \sum_{q} \sum_{r} \sum_{p} \text{DAESRTV}_{q, r, p, i}$$

$$\text{DAESRTV}_{q, r, p, i} = \text{RTSPP}_{p, i} * (\text{DAESR}_{q, r, p} * ¼)$$

Total Real-Time value of Day-Ahead Make-Whole Revenue for all RMR units by interval

$$\text{RMRDAMWREVTOT}_{i} = \text{DAMWRMRREVQSETOT}$$

The above variables are defined as follows:

Variable	Unit	Definition
LARMRAMT $_{q}$	$	*Load-Allocated Reliability Must Run Amount per QSE*—The amount charged to QSE *q* based on its LRS of the difference between the amount paid to all QSEs for RMR Service under this Section 6.6.6, Reliability Must Run Settlement, and the amount that would have been paid to the QSEs for the same RMR Units if they were not providing RMR Service under the other parts of this Section, Section 5, Transmission Security Analysis and Reliability Unit Commitment, and Section 4, Day-Ahead Operations, for the hour.
RMRSBAMTTOT	$	*RMR Standby Amount Total*—The total of the standby payments to all QSEs for all RMR Units, for the hour.
RMREAMTTOT	$	*RMR Energy Amount Total*—The total of the energy cost payments to all QSEs for all RMR Units, for the hour.
RMRAAMTTOT	$	*RMR Adjusted Amount Total*—The total of the adjusted amounts from all QSEs representing RMR Units for the revenues received for these units from RUC, Real-Time Operations and Ancillary Service Markets, for the hour.
RMRNPAMTTOT	$	*RMR Non-Performance Amount Total*—The total of the charges to all QSEs for unexcused misconduct events of all RMR Units, for the Operating Day.
RMRDAEREVTOT	$	*RMR Day-Ahead Energy Revenue Total*—The total of the revenues for the offers cleared in the DAM for all RMR Units, for the hour.
RMRDAESRTVTOT	$	*RMR Day-Ahead Energy Sale Real-Time Value Total*—The total of Real-Time value of the offers cleared in the DAM for all RMR Units, for the hour.
RMRDAMWREVTOT	$	*RMR Day-Ahead Make-Whole Revenue Total*—The total of the RMR

Variable	Unit	Definition
		Day-Ahead Make-Whole Revenue for all DAM-committed RMR Units for the hour.
HLRS $_q$	none	The hourly LRS calculated for QSE *q* for the hour. See Section 6.6.2.3, QSE Load Ratio Share for an Operating Hour.
RMRSBAMTQSETOT $_q$	$	*Reliability Must Run Standby Amount QSE Total per QSE*—The total of the Standby Payments to QSE *q* for the RMR Units represented by the same QSE for the hour.
RMREAMTQSETOT $_q$	$	*Reliability Must Run Energy Amount QSE Total per QSE*—The total of the energy payments to QSE *q* for the RMR Units represented by the same QSE for the hour.
RMRAAMT $_q$	$	*RMR Adjusted Amount per QSE*—The adjustment from QSE *q* standby payments and energy payments for all RMR Units represented by this QSE, for the revenues received for the same RMR Units from RUC and Real-Time Operations, for the hour.
RMRNPAMTQSETOT $_q$	$	*Reliability Must Run Unexcused Misconduct Amount QSE Total per QSE*—The total of the charges to QSE *q* for unexcused Misconduct Events of the RMR Units represented by the same QSE for the Operating Day.
DAEREV $_{q, r, p}$	$	*Day-Ahead Energy Revenue per QSE by Settlement Point per unit*—The revenue that ERCOT collects for the offer cleared in the DAM submitted for RMR Unit *r* at Resource Node *p* represented by QSE *q*, based on the DAM SPP, for the hour.
DAESRTV $_{q, r, p, i}$	$	*Day-Ahead Energy Sale Real-Time Value per QSE per Settlement Point per unit per interval*—The Real-Time value of the energy sold in the DAM from RMR Unit r at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval *i*.
DASPP $_p$	$/MWh	*Day-Ahead Settlement Point Price by Settlement Point*—The DAM SPP at Resource Node *p* for the hour.
RTSPP $_{p, i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point per interval*—The Real-Time SPP at Resource Node *p*, for the 15-minute Settlement Interval *i*.
DAESR $_{q, r, p}$	MW	*Day-Ahead Energy Sale from Resource per QSE by Settlement Point per unit*—The amount of energy cleared through Three-Part Supply Offers in the DAM and/or DAM Energy-Only Offer Curves for RMR Unit *r* at Resource Node *p* represented by QSE *q* for the hour.
DAESR $_{q, r, p, i}$	MW	*Day-Ahead Energy Sale from Resource per QSE by Settlement Point per unit per interval*—The amount of energy cleared through Three-Part Supply Offers in the DAM and/or DAM Energy-Only Offer Curves for Resource *r* at Resource Node *p* represented by QSE *q* for the hour that includes the 15-minute Settlement Interval *i*.
DAMWRMRREVQSETOT	$	*Day-Ahead Make-Whole RMR Revenue QSE Total per QSE*—The total of the Day-Ahead Make-Whole Revenue calculated for QSE *q* for DAM-committed RMR Units represented by this QSE for the hour.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	An RMR Unit.
i	none	A 15-minute Settlement Interval in the hour.
H	none	The number of hours of the Operating Day.

6.6.7 Voltage Support Settlement

6.6.7.1 Voltage Support Service Payments

(1) All other Generation Resources shall be eligible for compensation for Reactive Power production in accordance with Section 6.5.7.7, Voltage Support Service, only if ERCOT issues a Dispatch Instruction that results in the following unit operation:

(a) When ERCOT instructs the Generation Resource to exceed its Unit Reactive Limit (URL) and the Generation Resource provides additional Reactive Power, then ERCOT shall pay for the additional Reactive Power provided at a price that recognizes the avoided cost of reactive support Resources on the transmission network.

(b) Any real power reduction directed by ERCOT through (VDIs) to provide for additional reactive capability for voltage support must be compensated as a lost opportunity payment

(2) The payment for a given 15-minute Settlement Interval to each QSE representing a Generation Resource that operates in accordance with an ERCOT Dispatch Instruction is calculated as follows:

Depending on the Dispatch Instruction, payment for Volt Amps Reactive (var):

If $\text{VSSVARLAG}_{q,r} > 0$

$$\mathbf{VSSVARAMT}_{q,r} = \mathbf{(-1) * VSSVARPR * VSSVARLAG}_{q,r}$$

If $\text{VSSVARLEAD}_{q,r} > 0$

$$\mathbf{VSSVARAMT}_{q,r} = \mathbf{(-1) * VSSVARPR * VSSVARLEAD}_{q,r}$$

Where:

$$\text{VSSVARLAG}_{q,r} = \text{Max}\,[0, \text{Min}\,(¼ * \text{VSSVARIOL}_{q,r}, \text{RTVAR}_{q,r}) - (¼ * \text{URLLAG}_{q,r})]$$

$$\text{VSSVARLEAD}_{q,r} = \text{Max}\left\{0, [(¼ * \text{URLLEAD}_{q,r}) - \text{Max}\,((¼ * \text{VSSVARIOL}_{q,r}), \text{RTVAR}_{q,r})]\right\}$$

$$\text{URLLAG}_{q,r} = 0.32868 * \text{HSL}_{q,r}$$

$$\text{URLLEAD}_{q,r} = (-1) * 0.32868 * \text{HSL}_{q,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
VSSVARAMT $_{q, r}$	$	*Voltage Support Service var Amount per QSE per Generation Resource* - The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval.
VSSVARPR	$/Mvarh	*Voltage Support Service var Price* - The price for instructed Mvar beyond a Generation Resource's URL currently is $2.65/Mvarh (based on $50.00/installed kvar).
VSSVARLAG $_{q, r}$	Mvarh	*Voltage Support Service var Lagging per QSE per Generation Resource* - The instructed portion of the Reactive Power above the Generation Resource's lagging URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval.
VSSVARLEAD $_{q, r}$	Mvarh	*Voltage Support Service var Leading per QSE per Generation Resource* - The instructed portion of the Reactive Power below the Generation Resource's leading URL for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval.
VSSVARIOL $_{q, r}$	Mvar	*Voltage Support Service var Instructed Output Level per QSE per Generation Resource*—The instructed Reactive Power output level of Generation Resource *r* represented by QSE *q*, lagging Reactive Power if positive and leading Reactive Power if negative, for the 15-minute Settlement Interval.
RTVAR $_{q, r}$	MVARh	*Real-Time var per QSE per Resource*—The netted Reactive Energy measured for Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval.
URLLAG $_{q, r}$	Mvar	*Unit Reactive Limit Lagging per QSE per Resource*—The URL for lagging Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is positive.
URLLEAD $_{q, r}$	Mvar	*Unit Reactive Limit Leading per QSE per Resource*—The URL for leading Reactive Power of the Generation Resource *r* represented by QSE *q* as determined in accordance with these Protocols. Its value is negative.
HSL $_{q,r}$	MW	*High Sustained Limit*— The (HSL) of a Generation Resource as defined in Section 2, Definitions, for the hour that includes the Settlement Interval i.
q	none	A QSE.
r	none	A Generation Resource.

(3) The total additional compensation to each QSE for voltage support service for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{VSSVARAMTQSETOT_q} = \sum_{r} \mathbf{VSSVARAMT}_{\boldsymbol{q,r}}$$

Variable	Unit	Definition
VSSVARAMT $_{q, r}$	$	*Voltage Support Service var Amount per QSE per Generation Resource* - The payment to QSE *q* for the VSS provided by Generation Resource *r*, for the 15-minute Settlement Interval.
VSSVARAMTQSETOT $_{q}$	$	*Voltage Support var Amount QSE total per QSE* - The total of the payments to QSE *q* as compensation for VSS by this QSE for the 15-minute settlement interval.
q	none	A QSE.
r	none	A Generation Resource.

(4) The lost opportunity payment, if applicable:

$$\mathbf{VSSEAMT}_{q,r} = (-1) * \mathbf{Max}\,(0, \mathbf{RTSPP}_{p} * \mathbf{Max}\,(0, (\mathbf{HSL}_{q,r} * 1/4 - \mathbf{RTMG}_{q,r})) - (\mathbf{RTICHSL}_{q,r} - \mathbf{RTVSSAIEC}_{q,r} * (\mathbf{RTMG}_{q,r} - \mathbf{LSL}_{q,r} * 1/4)))$$

Where:

$$\text{RTICHSL}_{q,r} = \text{RTHSLAIEC}_{q,r} * (1/4 * \text{HSL}_{q,r} - 1/4 * \text{LSL}_{q,r})$$

The above variables are defined as follows:

Variable	Unit	Definition
VSSEAMT $_{q,r}$	$	*Voltage Support Service Energy Amount per QSE per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource r for the 15-minute Settlement Interval.
RTMG $_{q,r}$	MWh	*Real-Time Metered Generation per QSE per Resource*—The Real-Time metered generation of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval.
RTSPP$_p$	$	*Real-Time Settlement Point Price*—The Real-Time SPP at the Resource Node for the 15-minute Settlement Interval. -
RTVSSAIEC $_{q,r}$	$/MWh	*Real-Time Average Incremental Energy Cost per QSE per Resource*—The average incremental cost to operate (not subject to cost cap) the Generation Resource *r* represented by QSE *q* from its LSL to its metered MW output, for the 15-minute Settlement Interval.
RTICHSL $_{q,r}$	$	*Real-Time Incremental Cost Corresponding with HSL per QSE per Resource*—The incremental cost to operate (not subject to cost cap) Generation Resource *r* represented by QSE *q* from its LSL to its HSL, for the 15-minute Settlement Interval.
RTHSLAIEC $_{q,r}$	$/MWh	*Real-Time Average Incremental Energy Cost for the entire Energy Offer Curve through the HSL per QSE per Resource*—The average incremental cost to operate (not subject to cost cap) the Generation Resource r represented by QSE *q* from its LSL to its HSL, for the 15-minute Settlement Interval.
HSL $_{q,r}$	MW	*High Sustainable Limit Generation per QSE per Settlement Point per Resource*—The High Sustainable Limit of Generation Resource r represented by QSE *q* at Resource Node p for the hour that includes the 15-minute Settlement Interval.
LSL $_{q,r}$	MW	*Low Sustainable Limit Generation per QSE per Settlement Point per Resource*—The Low Sustainable Limit of Generation Resource r represented by QSE *q* at Resource Node p for the hour that includes the 15-minute Settlement Interval.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.

(5) The total of the payments to each QSE for ERCOT-directed power reduction to provide VSS for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{VSSEAMTQSETOT}_{q} = \sum_{r} \mathbf{VSSEAMT}_{q,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$VSSEAMTQSETOT_{q}$	$	*Voltage Support Service Lost Opportunity Amount QSE Total per QSE*—The total of the lost opportunity payments to QSE *q* for providing VSS for providing ERCOT-directed VSS for the 15-minute Settlement Interval.
$VSSEAMT_{q, r}$	$	*Voltage Support Service Energy Amount per QSE per Settlement Point per Generation Resource*—The lost opportunity payment to QSE *q* for ERCOT-directed VSS from Generation Resource r for the 15-minute Settlement Interval for the 15-minute Settlement Interval.
q	none	A QSE.
r	none	A Generation Resource.

6.6.7.2 Voltage Support Charge

ERCOT shall charge each QSE representing Load Serving Entities (LSEs) the total payment for VSS as specified in Section 6.6.7.1, Voltage Support Service Payments, based on a LRS. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LAVSSAMT}_{q} = \quad \mathbf{(-1) * (VSSVARAMTTOT + VSSEAMTTOT) * LRS}_{q}$$

Where:

$$\text{VSSVARAMTTOT} = \sum_{q} \text{VSSVARAMTQSETOT}_{q}$$

$$\text{VSSEAMTTOT} = \sum_{q} \text{VSSEAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LAVSSAMT_{q}$	$	*Load-Allocated Voltage Support Service Amount per QSE*—The charge to QSE *q* for VSS, for the 15-minute Settlement Interval.
VSSVARAMTTOT	$	*Voltage Support Service var Amount Total*—The total of payments to all QSEs providing VSS, for the 15-minute Settlement Interval.
$VSSVARAMTQSETOT_{q}$	$	*Voltage Support Service var Amount QSE Total per QSE*—The total of the payments to QSE *q* for providing VSS for the 15-minute Settlement Interval.
LRS_{q}	none	*The Load Ratio Share* calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
VSSEAMTTOT	$	*Voltage Support Service Lost Opportunity Amount Total*—The total of payments to all QSEs providing VSS in lieu of energy, for the 15-minute Settlement Interval.
$VSSEAMTQSETOT_{q}$	$	*Voltage Support Service Lost Opportunity Amount QSE Total per QSE*—The total of the payments to QSE *q* for providing VSS in lieu of energy, for the 15-minute Settlement Interval.
q	none	A QSE.

6.6.8 Black Start Capacity

6.6.8.1 Black Start Capacity Payment

(1) ERCOT shall pay an hourly standby fee to QSEs representing Black Start Resources. This standby fee is determined through a competitive annual bidding process, with an adjustment for reliability based on a six-month rolling availability equal to 85% in accordance with Section 22, Attachment A, Standard Form Black Start Agreement.

(2) ERCOT shall pay a Black Start standby payment to each QSE for each Black Start Resource. The payment for each hour is calculated as follows:

$$\mathbf{BSSAMT}_{q,\,r} = \mathbf{(-1) * BSSPR}_{q,\,r} \mathbf{\ * BSSARF}_{q,\,r}$$

Where:

Black Start Service Availability Reduction Factor

If ($BSSHREAF_{q,\,r} \geq 0.85$)

$$BSSARF_{q,\,r} = 1$$

Otherwise

$$BSSARF_{q,\,r} = \text{Max}\,(0,\ 1 - (0.85 - BSSHREAF_{q,\,r}) * 2)$$

Black Start Service Hourly Rolling Equivalent Availability Factor

If ($BSSEH_{q,\,r} < 4380$)

$$BSSHREAF_{q,\,r} = 1$$

Otherwise

$$BSSHREAF_{q,\,r} = \left(\sum_{hr=h-4379}^{h} BSSAFLAG_{q,r,hr}\right) / 4380$$

The above variables are defined as follows:

Variable	Unit	Definition
BSSAMT $_{q, r}$	$	*Black Start Service Amount per QSE per Resource by hour*—The standby payment to QSE *q* for the Black Start Service (BSS) provided by Resource *r*, for the hour.
BSSPR $_{q, r}$	$ per hour	*Black Start Service Price per QSE per Resource*—The standby price of BSS Resource *r* represented by QSE *q*, as specified in the BSS Agreement.
BSSARF $_{q, r}$	none	*Black Start Service Availability Reduction Factor per QSE per Resource by hour*—The availability reduction factor of Resource *r* represented by QSE *q* under the BSS Agreement, for the hour.
BSSHREAF $_{q, r}$	none	*Black Start Service Hourly Rolling Equivalent Availability Factor per QSE per Resource by hour*—The equivalent availability factor of the BSS Resource *r* represented by QSE *q* over 4,380 hours, for the hour.
BSSEH $_{q, r}$	none	*Black Start Service Elapsed number of Hours per QSE per Resource by hour*—The number of the elapsed hours of BSS Resource *r* represented by QSE *q* since the beginning of the BSS Agreement, for the hour.
BSSAFLAG $_{q, r, hr}$	none	*Black Start Service Availability Flag per QSE per Resource by hour*—The flag of the availability of BSS Resource *r* represented by QSE *q*, 1 for available and 0 for unavailable, for the hour.
q	none	A QSE.
r	none	A BSS Resource.
hr	none	The index of a given hour and the previous 4379 hours.
4380	none	The number of hours in a six-month period.

(3) The total of the payments to each QSE for all BSS Resources represented by this QSE for a given hour is calculated as follows:

$$\textbf{BSSAMTQSETOT}_{\boldsymbol{q}} = \sum_{r} \textbf{BSSAMT}_{\boldsymbol{q, r}}$$

The above variables are defined as follows:

Variable	Unit	Definition
BSSAMTQSETOT $_{q}$	$	*Black Start Service Amount QSE Total per QSE*—The total of the payments to QSE *q* for BSS provided by all the BSS Resources represented by this QSE for the hour *h*.
BSSAMT $_{q, r}$	$	*Black Start Service Amount per QSE per Resource*—The standby payment to QSE *q* for BSS provided by Resource *r*, for the hour.
q	none	A QSE.
r	none	A BSS Resource.

6.6.8.2 Black Start Capacity Charge

ERCOT shall allocate the total Black Start Service Capacity payment to the QSEs representing Loads based on a LRS. The resulting charge to each QSE for a given hour is calculated as follows:

$$\textbf{LABSSAMT}_{\boldsymbol{q}} = \textbf{(-1) * BSSAMTTOT * HLRS}_{\boldsymbol{q}}$$

Where:

$$\text{BSSAMTTOT} = \sum_{q} \text{BSSAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LABSSAMT $_q$	$	*Load-Allocated Black Start Service Amount per QSE*—The charge allocated to QSE *q* for the BSS, for the hour.
BSSAMTQSETOT $_q$	$	*Black Start Service Amount QSE Total per QSE*—The Black Start Service payment to QSE *q* for BSS Resource *r*, for the hour.
BSSAMTTOT	$	*Black Start Service Amount QSE Total ERCOT-Wide* — The total of the payments to QSE Q for BSS provided by all the BSS Resource represented by this QSE for the hour h.
HLRS $_q$	none	The hourly LRS calculated for QSE *q* for the hour. See Section 6.6.2.3, QSE Load Ratio Share for an Operating Hour.
q	none	A QSE.

6.6.9 *Emergency Operations Settlement*

Due to Emergency Conditions, additional compensation for each Generation Resource for which ERCOT provides an Emergency Base Point may be awarded to the QSE representing the Generation Resource. If the Emergency Base Point is higher than the SCED Base Point immediately before the Emergency Condition and the SPP at the Resource Node is lower than the Generation Resource's Energy Offer Curve price at the Emergency Base Point, ERCOT shall pay the QSE additional compensation for the additional energy above the SCED Base Point.

6.6.9.1 Payment for Emergency Power Increase Directed by ERCOT

(1) If the Emergency Base Point issued to a Generation Resource is higher than the SCED Base Point immediately before the Emergency Condition, then ERCOT shall pay the QSE an additional compensation for the Resource at its Resource Node Settlement Point. The payment for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{EMREAMT}_{q, r, p} = \textbf{(-1) * EMREPR}_{q, r, p} \textbf{ * EMRE}_{q, r, p}$$

Where:

$$\text{EMREPR}_{q, r, p} = \text{Max}\,(0, \text{EBPWAPR}_{q, r, p} - \text{RTSPP}_{p})$$

$$\text{EBPWAPR}_{q, r, p} = \sum_{y} (\text{EBPPR}_{q, r, p, y} * \text{EBP}_{q, r, p, y} * \text{TLMP}_{y}) \,/\, \sum_{y} (\text{EBP}_{q, r, p, y} * \text{TLMP}_{y})$$

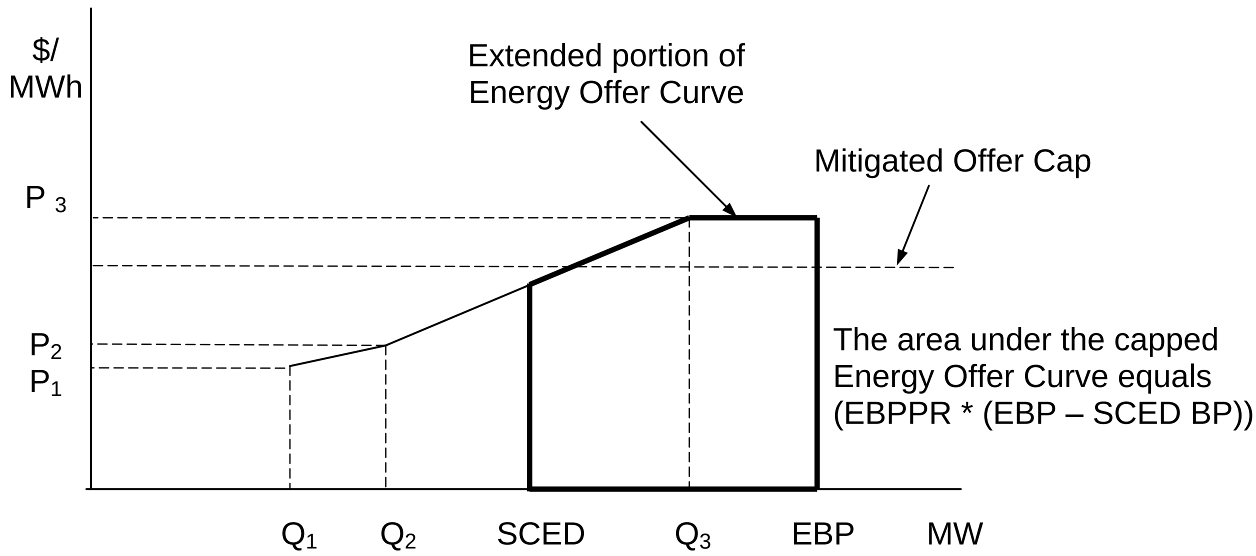
$$\text{EMRE}_{q, r, p} = \text{Max}\,(0, \text{Min}\,(\text{AEBP}_{q, r, p}, \text{RTMG}_{q, r, p}) - \tfrac{1}{4} * \text{BP}_{q, r, p})$$

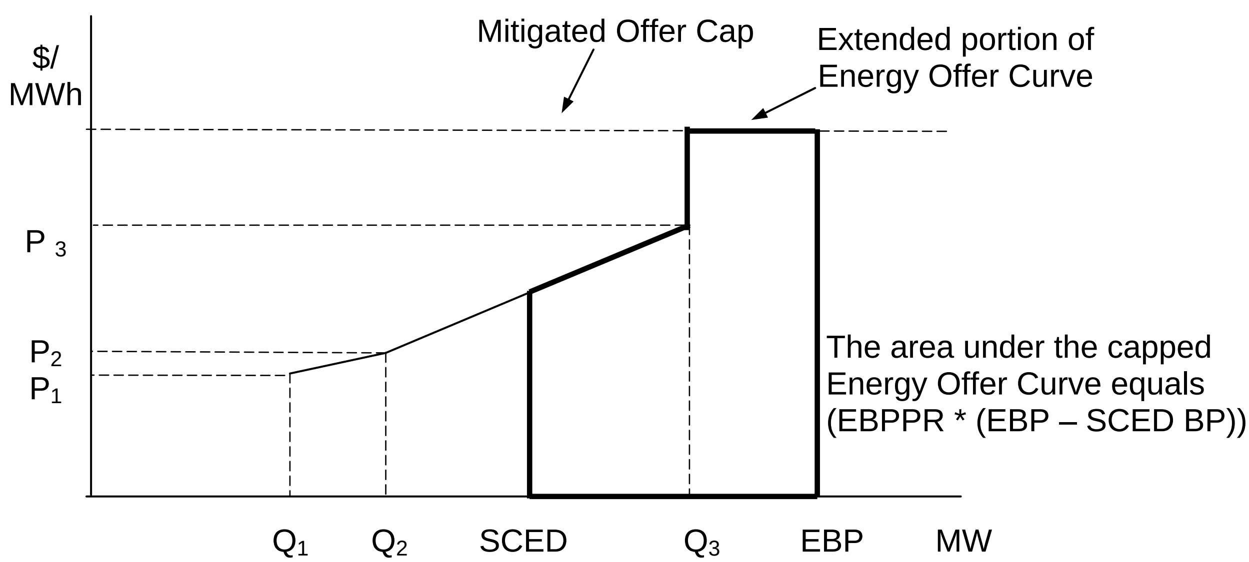
$$\text{AEBP}_{q, r, p} = \sum_{y} (\text{EBP}_{q, r, p, y} * \text{TLMP}_{y} / 3600)$$

The above variables are defined as follows:

Variable	Unit	Definition
EMREAMT $_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
EMREPR $_{q, r, p}$	$/MWh	*Emergency Energy Price per QSE per Settlement Point per Resource*—The compensation rate for the additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
EMRE $_{q, r, p}$	MWh	*Emergency Energy per QSE per Settlement Point per Resource*—The additional energy produced by Generation Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
EBPWAPR $_{q, r, p}$	$/MWh	*Emergency Base Point Weighted Average Price per QSE per Settlement Point per Resource*—The weighted average of the energy prices corresponding with the Emergency Base Points on the Energy Offer Curve for Resource *r* at Resource Node *p* represented by QSE *q*, for the 15-minute Settlement Interval.
BP $_{q, r, p}$	MW	*Base Point per QSE per Settlement Point per Resource*—The Base Point of Resource *r* at Resource Node *p* represented by QSE *q* from the SCED prior to the Emergency Condition.
AEBP $_{q, r, p}$	MWh	*Aggregated Emergency Base Point*—The Generation Resource's aggregated Emergency Base Point, for the 15-minute Settlement Interval.
EBP $_{q, r, p, y}$	MW	*Emergency Base Point per QSE per Settlement Point per Resource by interval*—The Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*. If a Base Point instead of an Emergency Base Point is effective during the interval *y*, its value equals the Base Point.
EBPPR $_{q, r, p, y}$	$/MWh	*Emergency Base Point Price per QSE per Settlement Point per Resource by interval*—The average incremental energy cost calculated per the Energy Offer Curve for the output levels between the SCED Base Point immediately before the Emergency Condition and the Emergency Base Point of Resource *r* at Resource Node *p* represented by QSE *q* for the Emergency Base Point interval or SCED interval *y*.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time SPP at Settlement Point *p*, for the 15-minute Settlement Interval.
RTMG $_{q, r, p}$	MWh	*Real-Time Metered Generation per QSE per Settlement Point per Resource*—The metered generation of Resource *r* at Resource Node *p* represented by QSE *q* in Real-Time for the 15-minute Settlement Interval.
TLMP $_{y}$	second	*Duration of Emergency Base Point interval or SCED interval per interval*—The duration of the portion of the Emergency Base Point interval or SCED interval *y* within the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource.
y	none	An Emergency Base Point interval or SCED interval that overlaps the 15-minute Settlement Interval.
3600	none	The number of seconds in one hour.

(2) The extension of the Energy Offer Curve is used to calculate the Emergency Base Point Price. If the Emergency Base Point MW value is greater than the largest MW value on the Energy Offer Curve submitted by the QSE for the Resource, then the Energy Offer Curve is extended to the Emergency Base Point MW value with a $/MWh value that is the Mitigated Offer Cap (pursuant to Section 4.4.9.4.1, Mitigated Offer Cap) for the highest MW output on the Energy Offer Curve submitted by the QSE for the Resource.





(3) The total additional compensation to each QSE for emergency power increases of Generation Resources for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{EMREAMTQSETOT}_{\,q} = \sum_{r}\sum_{p} \textbf{EMREAMT}_{\,q,\,r,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
$EMREAMTQSETOT_{q}$	$	*Emergency Energy Amount QSE Total per QSE*—The total of the payments to QSE *q* as additional compensation for emergency power increases of the Generation Resources represented by this QSE for the 15-minute Settlement Interval.
$EMREAMT_{q, r, p}$	$	*Emergency Energy Amount per QSE per Settlement Point per Resource*—The payment to QSE *q* as additional compensation for the additional energy produced by Generation Resource *r* at Resource Node *p* in Real-Time during the Emergency Condition, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource.

6.6.9.2 Charge for Emergency Power Increases

Each QSE shall pay a charge for emergency power increases based on its LRS of the total additional compensation for all Generation Resources that ERCOT provides Emergency Base Points higher than the SCED Base Point prior to the Emergency Condition. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LAEMREAMT}_{\boldsymbol{q}} = \mathbf{(-1) * EMREAMTTOT * LRS}_{\boldsymbol{q}}$$

Where:

$$EMREAMTTOT = \sum_{q} EMREAMTQSETOT_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LAEMREAMT_{q}$	$	*Load-Allocated Emergency Energy Amount per QSE*—The QSE *q*'s Load-Allocated amount of the total payments for all the Generation Resources with Real-Time Emergency Base Points, for the 15-minute Settlement Interval.
EMREAMTTOT	$	*Emergency Energy Amount Total*—The total of the payments to all QSEs as additional compensation for emergency power increases of the Generation Resources for the 15-minute Settlement Interval.
$EMREAMTQSETOT_{q}$	$	*Emergency Energy Amount QSE Total per QSE*—The total of the payments to QSE *q* as additional compensation for emergency power increases of the Generation Resources represented by this QSE for the 15-minute Settlement Interval.
LRS_{q}	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.

6.6.10 Real-Time Revenue Neutrality Allocation

(1) ERCOT must be revenue-neutral in each Settlement Interval. Each QSE receives an allocated share, on a LRS basis, of the net amount of:

(a) Real-Time Energy Imbalance payments or charges under Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(b) Real-Time Energy Imbalance payments or charges under Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

(c) Real-Time Energy Imbalance payments or charges under Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;

(d) Real-Time energy payments under Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;

(e) Real-Time energy payments under Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(f) Real-Time energy charge under Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export Represented by the QSE Under the Oklaunion Exemption;

(g) Real-Time congestion payments or charges under Section 6.6.4, Real-Time Congestion Payment or Charge for Self Schedules;

(h) Real-Time value of Day-Ahead energy sale from RMR Units under Section 6.6.6.5, RMR Service Charge; and

(i) Real-Time payments or charges to the Congestion Revenue Right (CRR) Owners under Section 7.9.2, Real-Time CRR Payments and Charges.

(2) The Real-Time Revenue Neutrality Allocation for each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LARTRNAMT}_{\boldsymbol{q}} = \mathbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTDCEXPAMTTOT + RTCCAMTTOT + RMRDAESRTVTOT + RTOBLAMTTOT / 4 + RTOPTAMTTOT / 4 + RTOPTRAMTTOT / 4) * LRS}_{\boldsymbol{q}}$$

Where:

Total Real-Time Energy Imbalance Payment (or Charge) at Settlement Point (or Hub)

$$\text{RTEIAMTTOT} = \sum_{q} \text{RTEIAMTQSETOT}_{q}$$

Total Real-Time Payment for BLT Resources

$$\text{BLTRAMTTOT} = \sum_{q} \text{BLTRAMTQSETOT}_{q}$$

Total Real-Time Payment for DC Tie Imports

$$\text{RTDCIMPAMTTOT} = \sum_{q} \text{RTDCIMPAMTQSETOT}_{q}$$

Total Real-Time Charge for DC Tie Exports (under “Oklaunion Exemption”)

$$\text{RTDCEXPAMTTOT} = \sum_{q} \text{RTDCEXPAMTQSETOT}_{q}$$

Total Real-Time Congestion Payment or Charge for Self-Schedules

$$\text{RTCCAMTTOT} = \sum_{q} \text{RTCCAMTQSETOT}_{q}$$

Total Real-Time Payment or Charge for Point-to-Point (PTP) Obligations

$$\text{RTOBLAMTTOT} = \sum_{q} \text{RTOBLAMTQSETOT}_{q}$$

Total Real-Time Payment for PTP Options

$$\text{RTOPTAMTTOT} = \sum_{o} \text{RTOPTAMTOTOT}_{o}$$

Total Real-Time Payment for PTP Options with Refund

$$\text{RTOPTRAMTTOT} = \sum_{o} \text{RTOPTRAMTOTOT}_{o}$$

The above variables are defined as follows:

Variable	Unit	Description
LARTRNAMT_{q}	\$	*Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*’s share of the total Real-Time revenue neutrality amount, for the 15-minute Settlement Interval.
RTEIAMTTOT_{q}	\$	*Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance Service at all Settlement Points (Resource, Load Zone or Hub) for the 15-minute Interval.
BLTRAMTTOT	\$	*Block Load Transfer Resource Amount Total*—The total of payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTTOT	\$	*Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval.
RTDCEXPAMTTOT	\$	*Real-Time DC Export Amount Total*—The summation of charges to all QSEs under the “Oklaunion Exemption” for DC Tie exports for the 15-minute Settlement Interval.
RTCCAMTTOT	\$	*Real-Time Energy Congestion Cost Amount Total*— The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval.
RMRDAESRTVTOT	\$	*RMR Day-Ahead Energy Sale Real-Time Value Total*—The total of the Real-Time value of the Day-Ahead energy sales from all RMR Units for the 15-minute Settlement Interval. See Section 6.6.6, Reliability Must-Run Settlement.
RTOBLAMTTOT	\$	*Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval.
RTOPTAMTTOT	\$	*Real-Time Option Amount Total*—The sum of all payments for PTP Options settled in Real-Time for the hour that includes the 15-minute Settlement Interval.

Variable	Unit	Description
RTOPTRAMTTOT	$	*Real-Time Option with Refund Amount Total*—The sum of all payments for PTP Options with Refund settled in Real-Time for the hour that includes the 15-minute Settlement Interval.
RTEIAMTQSETOT q	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance at all Resource Node Settlement Points for the 15-minute Settlement Interval.
RTCCAMTQSETOT q	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
BLTRAMTQSETOT q	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTQSETOT q	$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
RTDCEXPAMTQSETOT q	$	*Real-Time DC Export Amount QSE Total per QSE*—The total of the charges to QSE *q* for energy exported from the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
RTOBLAMTQSETOT q	$	*Real-Time Obligation Amount QSE Total per QSE*—The net total payment or charge to QSE *q* of all its PTP Obligations settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time.
RTOPTAMTOTOT o	$	*Real-Time Option Amount Owner Total per Owner*—The total payment for all the PTP Options held by the CRR owner *o* and settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.2, Payments for PTP Options Settled in Real-Time.
RTOPTRAMTOTOT o	$	*Real-Time Option with Refund Amount Owner Total per Owner*—The payment for the PTP Options with Refund held by the CRR owner *o* and settled in Real-Time for the hour that includes the 15-minute Settlement Interval. See paragraph (2) of Section 7.9.2.3, Payments for Non-Opt-In Entity (NOIE) PTP Options with Refund Settled in Real-Time.
LRS_{q}	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
o	none	A CRR owner.

(3) In the event that ERCOT is unable to execute the DAM, the Real-Time Revenue Neutrality Allocation for each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{LARTRNAMT}_{q} = \mathbf{(-1) * (RTEIAMTTOT + BLTRAMTTOT + RTDCIMPAMTTOT + RTDCEXPAMTTOT + RTCCAMTTOT + RMRDAESRTVTOT + NDRTOBLAMTTOT / 4 + NDRTOPTAMTTOT / 4 + NDRTOPTRAMTTOT / 4 + NDRTFGRAMTTOT / 4 + NDRTOBLRAMTTOT / 4) * LRS}_{q}$$

Where:

Total Real-Time Energy Imbalance Payment (or Charge) at Settlement Point (or Hub)

$$\text{RTEIAMTTOT} = \sum_{q} \text{RTEIAMTQSETOT}_{q}$$

Total Real-Time Payment for BLT Resources

$$\text{BLTRAMTTOT} = \sum_{q} \text{BLTRAMTQSETOT}_{q}$$

Total Real-Time Payment for DC Tie Imports

$$\text{RTDCIMPAMTTOT} = \sum_{q} \text{RTDCIMPAMTQSETOT}_{q}$$

Total Real-Time Charge for DC Tie Exports (under "Oklaunion Exemption")

$$\text{RTDCEXPAMTTOT} = \sum_{q} \text{RTDCEXPAMTQSETOT}_{q}$$

Total Real-Time Congestion Payment or Charge for Self Schedules

$$\text{RTCCAMTTOT} = \sum_{q} \text{RTCCAMTQSETOT}_{q}$$

Total Real-Time Payment or Charge for PTP Obligations when ERCOT is unable to execute the DAM

$$\text{NDRTOBLAMTTOT} = \sum_{o} \text{NDRTOBLAMTOTOT}_{o}$$

Total Real-Time Payment for PTP Options when ERCOT is unable to execute the DAM

$$\text{NDRTOPTAMTTOT} = \sum_{o} \text{NDRTOPTAMTOTOT}_{o}$$

Total Real-Time Payment for PTP Options with Refund when ERCOT is unable to execute the DAM

$$\text{NDRTOPTRAMTTOT} = \sum_{o} \text{NDRTOPTRAMTOTOT}_{o}$$

Total Real-Time Payment for Flowgate Rights (FGRs) when ERCOT is unable to execute the DAM

$$\text{NDRTFGRAMTTOT} = \sum_{o} \text{NDRTFGRAMTOTOT}_{o}$$

Total Real-Time Payment or Charge for PTP Obligations with Refund when ERCOT is unable to execute the DAM

$$\text{NDRTOBLRAMTTOT} = \sum_{o} \text{NDRTOBLRAMTOTOT}_{o}$$

The above variables are defined as follows:

Variable	Unit	Description

Variable	Unit	Description
LARTRNAMT $_q$	$	*Load-Allocated Real-Time Revenue Neutrality Amount per QSE*—The QSE *q*'s share of the total Real-Time revenue neutrality amount for the 15-minute Settlement Interval.
RTEIAMTTOT	$	*Real-Time Energy Imbalance Amount Total*—The total net payments and charges for Real-Time Energy Imbalance at all Settlement Points (Resource, Load Zone, or Hub) for the 15-minute Interval.
BLTRAMTTOT	$	*Block Load Transfer Resource Amount Total*—The total of the payments for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.
RTDCIMPAMTTOT	$	*Real-Time DC Import Amount Total*—The summation of payments for DC Tie imports for the 15-minute Settlement Interval.
RTDCEXPAMTTOT	$	*Real-Time DC Export Amount Total*—The summation of charges to all QSEs that are under the "Oklaunion Exemption" for DC Tie exports for the 15-minute Settlement Interval.
RTCCAMTTOT	$	*Real-Time Energy Congestion Cost Amount Total*—The total net congestion payments and charges for all Self-Schedules for the 15-minute Settlement Interval.
RMRDAESRTVTOT	$	*RMR Day-Ahead Energy Sale Real-Time Value Total*—The total of the Real-Time value of the Day-Ahead energy sales from all RMR Units for the 15-minute Settlement Interval. See Section 6.6.6, Reliability Must-Run Settlement.
NDRTOBLAMTTOT	$	*No DAM Real-Time Obligation Amount Total*—The sum of all payments and charges for PTP Obligations settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOPTAMTTOT	$	*No DAM Real-Time Option Amount Total*—The sum of all payments for PTP Options settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOPTRAMTTOT	$	*No DAM Real-Time Option with Refund Amount Total*—The sum of all payments for PTP Options with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTFGRAMTTOT	$	*No DAM Real-Time FGR Amount Total*— The sum of all payments for FGRs settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
NDRTOBLRAMTTOT	$	*No DAM Real-Time Obligation with Refund Amount Total*— The sum of all payments for PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour that includes the 15-minute Settlement Interval.
RTEIAMTQSETOT $_q$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval.
RTCCAMTQSETOT $_q$	$	*Real-Time Congestion Cost Amount QSE Total per QSE*—The total net congestion payments and charges to QSE *q* for its Self-Schedules for the 15-minute Settlement Interval.
BLTRAMTQSETOT $_q$	$	*Block Load Transfer Resource Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy delivered into the ERCOT Region through BLT points for the 15-minute Settlement Interval.

Variable	Unit	Description
RTDCIMPAMTQSETOT $_q$	$	*Real-Time DC Import Amount QSE Total per QSE*—The total of the payments to QSE *q* for energy imported into the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
RTDCEXPAMTQSETOT $_q$	$	*Real-Time DC Export Amount QSE Total per QSE*—The total of the charges to QSE *q* for energy exported from the ERCOT Region through DC Ties for the 15-minute Settlement Interval.
NDRTOBLAMTOTOT $_o$	$	*No DAM Real-Time Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* of all its PTP Obligations settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTAMTOTOT $_o$	$	*No DAM Real-Time Option Amount Owner Total per CRR Owner*—The total payment to CRR owner *o* for all its PTP Options settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTRAMTOTOT $_o$	$	*No DAM Real-Time Option with Refund Amount Owner Total per CRR Owner*—The total payment to NOIE CRR owner *o* for all its PTP Options with Refund settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTFGRAMTOTOT $_o$	$	*No DAM Real-Time FGR Amount Owner Total per CRR Owner*—The total payment to CRR owner *o* of all its FGRs settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOBLRAMTOTOT $_o$	$	*No DAM Real-Time Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR owner *o* for all its PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
LRS $_q$	none	The LRS calculated for QSE *q* for the 15-minute Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
o	none	A CRR Owner.

6.6.11 Emergency Interruptible Load Service (EILS) Capacity

6.6.11.1 EILS Capacity Payments

(1) ERCOT shall pay, for each EILS Contract Period, the QSEs representing EILS Loads as follows:

$$\mathbf{EIL}_{\,qce(tp)} = \mathbf{-1 * OFFERPrice}_{\,qce(tp)} \mathbf{* OFFERValue}_{\,qce(tp)} \mathbf{* AvailFactor}_{\,qce(tp)} \mathbf{* EILFactor}_{\,qce(tp)} \mathbf{* TPh}$$

Where:

$$\text{QSE\_EIL}_{\,qc(tp)} = \sum \text{EIL}_{\,qce(tp)}$$

$$\text{Total\_OFFERValue}_{\,qc(tp)} = \sum \text{OFFERValue}_{\,qce(tp)}$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	A QSE.
c	None	EILS Contract Period.
e	None	Individual EILS Load.
tp	None	Hours in an EILS Time Period.
TPh	None	Number of hours in an EILS Time Period.
AvailFactor $_{qce(tp)}$	%	EILS availability factor for an EILS Time Period, as calculated (and revised if necessary) in Section 8.1.3.1, Performance Criteria for EILS Loads.
OFFERPrice $_{qce(tp)}$	$ per MW	Contracted Offer Price for an EILS Load for an EILS Time Period.
OFFERValue $_{qce(tp)}$	MW	Contracted capacity for an EILS Load for an EILS Time Period.
Total_OFFERValue $_{qc(tp)}$	MW	Total contracted EILS capacity for a QSE in an EILS Time Period.
EILFactor $_{qce(tp)}$	%	EILS event performance factor for an EILS Time Period, as described in Section 8.1.3.1, Performance Criteria for EILS Loads.
EIL $_{qce(tp)}$	$	EILS total payment for an EILS Load for an EILS Time Period.
QSE_EIL $_{qc(tp)}$	$	EILS total payment to a QSE for an EILS Time Period.

(2) ERCOT shall assess the settlement payment for EILS for each EILS Contract Period on the Initial Settlement Statement for an Operating Day no later than 70 days after the last Operating Day of the EILS Contract Period. For dispute purposes, ERCOT and QSEs shall use the Operating Day of the Settlement Statement on which the EILS payment appears. The timeliness of a dispute concerning EILS pursuant to Section 9.14.2, Notice of Dispute, shall be determined by the Operating Day of the Settlement Statement on which the EILS payment appears.

6.6.11.2 EILS Capacity Charge

(1) ERCOT shall allocate costs for an EILS Contract Period based on the LRS of each QSE during each EILS Time Period in an EILS Contract Period. A QSE's LRS for an EILS Time Period shall be the QSE's total Load for the EILS Time Period divided by the total ERCOT Load in the EILS Time Period.

(2) If a QSE opts for EILS Self-Provision, the QSE's LRS for an EILS Time Period shall be the QSE's total Load for the EILS Time Period, divided by the total ERCOT Load in the EILS Time Period. The QSE's LRS for an EILS Time Period is then compared to the amount of EILS Self-Provision by the QSE for an EILS Time Period.

(a) If the QSE's EILS Self-Provision amount is equal to the QSE's LRS multiplied by the total contracted amount of EILS for an EILS Time Period, the QSE's obligation for that EILS Time Period is zero.

(b) If the QSE's EILS Self-Provision amount is greater than the QSE's LRS multiplied by the total contracted amount of EILS for an EILS Time Period, the QSE's obligation for that EILS Time Period is zero.

(c) If the QSE's EILS Self-Provision amount is less than the QSE's LRS multiplied by the total contracted amount of EILS for an EILS Time Period, the QSE's obligation for that EILS Time Period is the difference between the EILS Self-Provision amount and the QSE's LRS.

(3) ERCOT shall calculate each QSE's EILS capacity charge as follows:

$$\mathbf{LAEIL}_{qc(tp)} = \mathbf{EILP}_{qc(tp)} * \mathbf{EILO}_{qc(tp)}$$

Where:

$$\text{EILO}_{qc(tp)} = \text{Max}[0,(\text{LRS}_{qc(tp)} * (\text{Total\_OFFERValue}_{qc(tp)} + \sum(\text{SP}_{qc(tp)})) - \text{SP}_{qc(tp)})]$$

$$\text{EILP}_{qc(tp)} = \sum(\text{QSE\_EIL}_{qc(tp)}) / \sum\text{EILO}_{qc(tp)}$$

$$\text{SP}_{qc(tp)} = \sum_{i=1}^{n} [(\text{SPC}_{qc(tp)}) * \text{AvailFactor}_{qce(tp)} * \text{EILFactor}_{qce(tp)}]$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	A QSE.
c	None	EILS Contract Period.
tp	None	Hours in an EILS Time Period.
n	None	The number of committed EILS Loads for a QSE in an EILS Time Period.
i	None	An index number used to identify a QSE's EILS Load for an EILS Time Period.
$\text{EILO}_{qc(tp)}$	MW	EILS net obligation per QSE per hour for an EILS Time Period.
$\text{EILP}_{qc(tp)}$	$	Offer Price for the EILS Load for an EILS Time Period.
$\text{SP}_{qc(tp)}$	MW	EILS provided by the QSE through EILS Self-Provision for an EILS Time Period.
$\text{Total\_OFFERValue}_{qc(tp)}$	MW	Total Capacity for an EILS Load contracted for EILS for an EILS Time Period.
$\text{SPC}_{qc(tp)}$	MW per Hour	Self-providing QSE's commitment for an EILS Time Period.
$\text{AvailFactor}_{qce(tp)}$	%	Availability factor for an EILS Load in an EILS Time Period as calculated (and revised if necessary) pursuant to Section 8.1.3.1, Performance Criteria for EILS Loads.

EILFactor $_{qce(tp)}$	%	Event performance factor for an EILS Load in an EILS Time Period as calculated pursuant to Section 8.1.3.1, Performance Criteria for EILS Loads.
QSE_EIL $_{qc(tp)}$	$	EILS total payments to QSEs for an EILS Time Period.
LRS $_{qc(tp)}$	%	EILS LRS for the QSE for an EILS Time Period.
LAEIL $_{qc(tp)}$	$	EILS charge for the QSE for an EILS Time Period.

(4) ERCOT shall assess the EILS capacity charge as determined above for each EILS Time Period in an EILS Contract Period on the Initial Settlement Statement for an Operating Day no later than 70 calendar days after the last Operating Day of the EILS Contract Period. For dispute purposes, ERCOT and QSEs shall use the Operating Day of the Settlement Statement on which the EILS payment appears. The timeliness of a dispute concerning EILS pursuant to Section 9.14.2, Notice of Dispute, shall be determined by the Operating Day of the Settlement Statement on which the EILS obligation appears.

6.7 Real-Time Settlement Calculations for the Ancillary Services

6.7.1 Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Service Market

If a Supplemental Ancillary Services Market (SASM) is executed for one or more Operating Hours for any reason, ERCOT shall pay Qualified Scheduling Entities (QSEs) for their Ancillary Service Offers cleared in the SASM, based on the Market Clearing Price for Capacity (MCPC) for that SASM and that service. By service and by SASM, the payment to each QSE for a given Operating Hour is calculated as follows:

(1) For Regulation Up (Reg-Up), if applicable:

$$\mathbf{RTPCRUAMT}_{\,q,\,m} \quad = \quad \mathbf{(-1) * MCPCRU}_{\,m} \mathbf{* RTPCRU}_{\,q,\,m}$$

Where:

$$\text{RTPCRU}_{\,q,\,m} \quad = \quad \sum_{r} \text{PCRUR}_{\,q,\,r,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
RTPCRUAMT $_{q, m}$	$	*Procured Capacity for Reg-Up Amount by QSE by market*—The payment to QSE *q* for the Ancillary Service Offers cleared in the market *m* to provide Reg-Up, for the hour.
MCPCRU $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by market* —The MCPC for Reg-Up from the market *m*, for the hour.
PCRU $_{q, m}$	MW	*Procured Capacity for Reg-Up by QSE by market*—The portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Up, for the hour.
RTPCRUR $_{q, r, m}$	MW	*Procured Capacity for Reg-Up from Resource per Resource per QSE by market*—

		The Reg-Up capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour.
m	none	A SASM.
q	none	A QSE.
r	none	A Generation Resource.

(2) For Regulation Down (Reg-Down), if applicable:

$$\mathbf{RTPCRDAMT}_{q,\,m} = \mathbf{(-1) * MCPCRD}_{q,\,m}\mathbf{ * RTPCRD}_{q,\,m}$$

Where:

$$\text{RTPCRD}_{q,\,m} = \sum_{r} \text{PCRDR}_{r,\,q,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTPCRDAMT}_{q,\,m}$	$	*Procured Capacity for Reg-Down Amount by QSE by market*—The payment to QSE *q* for the Ancillary Service Offers cleared in the market *m* to provide Reg-Down, for the hour.
MCPCRD_{m}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by market*—The MCPC for Reg-Down from the market *m*, for the hour.
$\text{RTPCRD}_{q,\,m}$	MW	*Procured Capacity for Reg-Down by QSE by market*—The portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Down, for the hour.
$\text{PCRDR}_{r,\,q,\,m}$	MW	*Procured Capacity for Reg-Down from Resource per Resource per QSE by market*—The Reg-Down capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour
m	none	A SASM.
q	none	A QSE.
r	none	A Generation Resource.

(3) For Responsive Reserve, if applicable:

$$\mathbf{RTPCRRAMT}_{q,\,m} = \mathbf{(-1) * MCPCRR}_{m}\mathbf{ * RTPCRR}_{q,\,m}$$

Where:

$$\text{RTPCRR}_{q,\,m} = \sum_{r} \text{PCRRR}_{q,\,r,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
$\text{RTPCRRAMT}_{q,\,m}$	$	*Procured Capacity for Responsive Reserve Amount by QSE by market*—The payment to QSE *q* for the Ancillary Service Offer cleared in the market *m* to provide Responsive Reserve, for the hour.

$MCPCRR_{m}$	\$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve by market*—The MCPC for Responsive Reserve from the market *m*, for the hour.
$RTPCRR_{q, m}$	MW	*Procured Capacity for Responsive Reserve by QSE by market*—The portion of QSE *q* Ancillary Service Offers cleared in the market *m* to provide Responsive Reserve, for the hour.
$PCRRR_{q,r, m}$	MW	*Procured Capacity for Responsive Reserve from Resource per Resource per QSE by market*—The Responsive Reserve capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour.
m	none	A SASM.
q	none	A QSE.
r	none	A Generation Resource.

(4) For Non-Spin, if applicable:

$$\mathbf{RTPCNSAMT}_{q, m} = \mathbf{(-1) * MCPCNS}_{m} \mathbf{* RTPCNS}_{q, m}$$

Where:

$$RTPCNS_{q, m} = \sum_{r} PCNSR_{q, r, m}$$

The above variables are defined as follows:

Variable	Unit	Description
$RTPCNSAMT_{q, m}$	\$	*Procured Capacity for Non-Spin Amount by QSE by market*—The payment to QSE *q* for Ancillary Service Offer cleared in the market *m* to provide Non-Spin, for the hour.
$MCPCNS_{m}$	\$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by market*—The MCPC for Non-Spin from the market *m*, for the hour.
$RTPCNS_{q, m}$	MW	*Procured Capacity for Non-Spin by QSE by market*—The portion of QSE *q*'s Ancillary Service Offer cleared in the market *m* to provide Non-Spin, for the hour.
$PCNSR_{q,r, m}$	MW	*Procured Capacity for Non-Spin from Resource per Resource per QSE by market*—The Non-Spin capacity quantity awarded to QSE *q* in the market *m* for Resource *r* for the hour.
m	none	A SASM.
q	none	A QSE.
r	none	A Generation Resource.

6.7.2 Charges for Ancillary Service Capacity Replaced Due to Failure to Provide

A charge to each QSE that fails on its Ancillary Service Supply Responsibility, whether or not a SASM is executed due to its failure to supply, is calculated based on the greatest of the MCPC in the Day-Ahead Market (DAM) or any SASM for the same Operating Hour. By service, the charge to each QSE for a given Operating Hour is calculated as follows:

(1) For Reg-Up, if applicable:

$$\textbf{RUFQAMT}_{\boldsymbol{q}} = \underset{m}{Max}\,(\textbf{MCPCRU}_{\boldsymbol{m}}) * \textbf{RUFQ}_{\boldsymbol{q}}$$

The above variables are defined as follows:

Variable	Unit	Description
RUFQAMT $_q$	$	*Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
MCPCRU $_m$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by market*—The MCPC for Reg-Up in the market *m*, for the hour.
RUFQ $_q$	MW	*Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
m	none	The DAM or a SASM for the given Operating Hour.
q	none	A QSE.

(2) For Reg-Down, if applicable:

$$\textbf{RDFQAMT}_{\boldsymbol{q}} = \underset{m}{Max}\,(\textbf{MCPCRD}_{\boldsymbol{m}}) * \textbf{RDFQ}_{\boldsymbol{q}}$$

The above variables are defined as follows:

Variable	Unit	Description
RDFQAMT $_q$	$	*Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
MCPCRD $_m$	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by market*—The MCPC for Reg-Down in the market *m*, for the hour.
RDFQ $_q$	MW	*Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
m	none	The DAM or a SASM for the given Operating Hour.
q	none	A QSE.

(3) For Responsive Reserve, if applicable:

$$\textbf{RRFQAMT}_{\boldsymbol{q}} = \underset{m}{Max}\,(\textbf{MCPCRR}_{\boldsymbol{m}}) * \textbf{RRFQ}_{\boldsymbol{q}}$$

The above variables are defined as follows:

Variable	Unit	Description
RRFQAMT $_q$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Responsive Reserve, for the hour.
MCPCRR $_m$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per market*—The MCPC for Responsive Reserve in the market *m*, for the hour.
RRFQ $_q$	MW	*Responsive Reserve Failure Quantity per QSE* - QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Responsive Reserve, for the hour.
m	none	The DAM or a SASM for the given Operating Hour.
q	none	A QSE.

(4) For Non-Spin, if applicable:

$$\textbf{NSFQAMT}_{q} = \underset{m}{Max}(\textbf{MCPCNS}_{m}) * \textbf{NSFQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
$NSFQAMT_{q}$	$	*Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$MCPCNS_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by market*—The MCPC for Non-Spin in the market *m*, for the hour.
$NSFQ_{q}$	MW	*Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
m	none	The DAM or a SASM for the given Operating Hour.
q	none	A QSE.

6.7.3 Adjustments to Cost Allocations for Ancillary Services Procurement

Each QSE, for which ERCOT purchases Ancillary Service capacity in the DAM and SASMs (if any), is charged for the QSE's share of the net costs incurred for each service. For each QSE, its share of the DAM costs has been calculated in Section 4.6.4, Settlement of Ancillary Services Procured in the DAM; its share of the net total costs incurred in both DAM and SASMs less its DAM charge is calculated in this section.

(1) For Reg-Up, if applicable:

(a) The net total costs for Reg-Up for a given Operating Hour is calculated as follows:

$$\textbf{RUCOSTTOT} = (-1) * (\sum_{m} (\textbf{RTPCRUAMTTOT}_{m}) + \textbf{PCRUAMTTOT} + \textbf{RUFQAMTTOT})$$

Where:

Total payment of SASM-procured capacity for Reg-Up by market

$$RTPCRUAMTTOT_{m} = \sum_{q} RTPCRUAMT_{q,m}$$

Total payment of DAM-procured capacity for Reg-Up

$$PCRUAMTTOT = \sum_{q} PCRUAMT_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Up

$$RUFQAMTTOT = \sum_{q} RUFQAMT_{q}$$

Total payment of SASM procured capacity for Reg-Up by QSE

$$\text{RTPCRUAMTQSETOT}_{q} = \sum_{m} \text{RTPCRUAMT}_{q, m}$$

The above variables are defined as follows:

Variable	Unit	Description
RUCOSTTOT	$	*Reg-Up Cost Total*—The net total costs for Reg-Up for the hour.
RTPCRUAMTTOT $_{m}$	$	*Procured Capacity for Reg-Up Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
RTPCRUAMT $_{q, m}$	$	*Procured Capacity for Reg-Up Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
RUFQAMTTOT	$	*Reg-Up Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures on their Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
RUFQAMT $_{q}$	$	*Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RTPCRUAMTQSETOT $_{q}$	$	*Procured Capacity for Reg-Up Amount Total per QSE*—The total payments to a QSE in all SASM markets for the Ancillary Service Offers cleared for Reg-Up Service, for the hour.
PCRUAMT $_{q}$	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up Service payment for QSE *q* for the hour.
PCRUAMTTOT	$	*Procured Capacity for Reg-Up Amount Total in DAM*—The total of the DAM Reg-Up payments for all QSEs for the hour.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(b) Each QSE's share of the net total costs for Reg-Up for the Operating Hour is calculated as follows:

$$\mathbf{RUCOST}_{q} = \mathbf{RUPR * RUQ}_{q}$$

Where:

$$\text{RUPR} = \text{RUCOSTTOT / RUQTOT}$$

$$\text{RUQTOT} = \sum_{q} \text{RUQ}_{q}$$

$$\text{RUQ}_{q} = \text{RUO}_{q} - \text{SARUQ}_{q}$$

$$\text{RUO}_{q} = \sum_{q} (\text{SARUQ}_{q} + \sum_{m} (\text{RTPCRU}_{q, m}) + \text{PCRU}_{q} - \text{RURP}_{q} - \text{RUFQ}_{q}) * \text{HLRS}_{q} + \text{RURP}_{q}$$

$$\text{SARUQ}_{q} = \text{DASARUQ}_{q} + \text{RTSARUQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RUCOST $_q$	$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up, for the hour.
RUPR	$/MW per hour	*Reg-Up Price***—**The price for Reg-Up calculated based on the net total costs for Reg-Up, for the hour.
RUCOSTTOT	$	*Reg-Up Cost Total*—The net total costs for Reg-Up for the hour. See item (a) above.
RUQTOT	MW	*Reg-Up Quantity Total*—The sum of every QSE's portion of its Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
RUQ $_q$	MW	*Reg-Up Quantity per QSE*—The portion of QSE *q*'s Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
RUO $_q$	MW	*Reg-Up Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASARUQ $_q$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARUQ $_q$	MW	*Self-Arranged Reg-Up Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for all SASMs.
RTPCRU $_{q, m}$	MW	*Procured Capacity for Reg-Up per QSE by market***—**The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Up, for the hour.
RUFQ $_q$	MW	*Reg-Up Failure Quantity per QSE***—**QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
HLRS $_q$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.3, QSE Load Ratio Share for an Operating Hour.
RURP $_q$	MW	*Reg-Up Replacement per QSE*—The total Reg-Up capacity that was a portion of the Ancillary Service Supply Responsibility of QSE *q* but is replaced in a SASM for the hour.
PCRU $_q$	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE for the hour.
SARUQ $_q$	MW	*Total Self-Arranged Reg-Up Quantity per QSE for all markets*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Reg-Up for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTRUAMT}_{q} = \quad \mathbf{RUCOST}_{q} - \mathbf{DARUAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUAMT $_q$	$	*Real-Time Reg-Up Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Reg-Up, for the hour.
RUCOST $_q$	$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up, for the hour.
DARUAMT $_q$	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Up, for the hour.
q	none	A QSE.

(2) For Reg-Down, if applicable:

(a) The net total costs for Reg-Down for a given Operating Hour is calculated as follows:

$$\textbf{RDCOSTTOT} = \textbf{(-1) * (}\sum_{m} \textbf{(RTPCRDAMTTOT}_{m} \textbf{+ PCRDAMTTOT + RDFQAMTTOT)}$$

Where:

Total payment of SASM-procured capacity for Reg-Down by market

$$\text{RTPCRDAMTTOT}_{m} = \sum_{q} \text{RTPCRDAMT}_{q,\, m}$$

Total payment of DAM-procured capacity for Reg-Down

$$\text{PCRDAMTTOT} = \sum_{q} \text{PCRDAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Down

$$\text{RDFQAMTTOT} = \sum_{q} \text{RDFQAMT}_{q}$$

Total payment of SASM procured capacity for Reg-Down by QSE

$$\text{RTPCRDAMTQSETOT}_{q} = \sum_{m} \text{RTPCRDAMT}_{q,\, m}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
RDCOSTTOT	$	*Reg-Down Cost Total*—The net total costs for Reg-Down for the hour.
RTPCRDAMTTOT_{m}	$	*Procured Capacity for Reg-Down Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.
$\text{RTPCRDAMT}_{q,\, m}$	$	*Procured Capacity for Reg-Down Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.
RDFQAMTTOT	$	*Reg-Down Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures on their Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
RDFQAMT_{q}	$	*Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
$\text{RTPCRDAMTQSETOT}_{q}$	$	*Procured Capacity for Reg-Down Amount Total per QSE*—The total payments to a QSE in all SASM markets for the Ancillary Service Offers cleared for Reg-Down Service, for the hour.
PCRDAMT_{q}	$	*Procured Capacity for Regulation Down Amount per QSE for DAM*—The DAM Reg-Down Service payment for QSE *q* for the hour.
PCRDAMTTOT	$	*Procured Capacity for Reg-Down Amount Total in DAM*—The total of the DAM Reg-Down payments for all QSEs for the hour.

Variable	Unit	Description
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(b) Each QSE's share of the net total costs for Reg-Down for the Operating Hour is calculated as follows:

$$\mathbf{RDCOST}_{q} = \mathbf{RDPR * RDQ}_{q}$$

Where:

$$\text{RDPR} = \text{RDCOSTTOT / RDQTOT}$$

$$\text{RDQTOT} = \sum_{q} \text{RDQ}_{q}$$

$$\text{RDQ}_{q} = \text{RDO}_{q} - \text{SARDQ}_{q}$$

$$\text{RDO}_{q} = \sum_{q} (\text{SARDQ}_{q} + \sum_{m} (\text{RTPCRD}_{q,m}) + \text{PCRD}_{q} - \text{RDRP}_{q} - \text{RDFQ}_{q}) * \text{HLRS}_{q} + \text{RDRP}_{q}$$

$$\text{SARDQ}_{q} = \text{DASARDQ}_{q} + \text{RTSARDQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RDCOST_{q}	$	*Reg-Down Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Down, for the hour.
RDPR	$/MW per hour	*Reg-Down Price*—The price for Reg-Down calculated based on the net total costs for Reg-Down, for the hour.
RDCOSTTOT	$	*Reg-Down Cost Total*—The net total costs for Reg-Down for the hour. See item (a) above.
RDQTOT	MW	*Reg-Down Quantity Total*—The sum of every QSE's portion of its Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
RDQ_{q}	MW	*Reg-Down Quantity per QSE*—The portion of QSE *q*'s net Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
RDO_{q}	MW	*Reg-Down Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASARDQ_{q}	MW	*Self-Arranged Reg-Down Quantity per QSE for DAM*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARDQ_{q}	MW	*Self-Arranged Reg-Down Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for all SASMs.
$\text{RTPCRD}_{q, m}$	MW	*Procured Capacity for Reg-Down per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Down, for the hour.
RDFQ_{q}	MW	*Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
HLRS_{q}		*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.3.

Variable	Unit	Description
RDRP $_q$	MW	*Reg-Down Replacement per QSE per market*—The total Reg-Down capacity that was a portion of the Ancillary Service Supply Responsibility of QSE *q* but is replaced in a SASM, for the hour.
PCRD $_q$	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down Service capacity quantity awarded to QSE q in the DAM for all the Resources represented by the QSE for the hour.
SARDQ $_q$	MW	*Total Self-Arranged Reg-Down Quantity per QSE for all markets*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Reg-Down for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\textbf{RTRDAMT}_{q} = \textbf{RDCOST}_{q} - \textbf{DARDAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDAMT $_q$	$	*Real-Time Reg-Down Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Reg-Down, for the hour.
RDCOST $_q$	$	*Reg-Down Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Down, for the hour.
DARDAMT $_q$	$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the hour.
q	none	A QSE.

(3) For Responsive Reserve (RRS) service, if applicable:

(a) The net total costs for Responsive Reserve for a given Operating Hour is calculated as follows:

$$\textbf{RRCOSTTOT} = \textbf{(-1) * (}\sum_{m} \textbf{(RTPCRRAMTTOT}_{m}\textbf{) + PCRRAMTTOT + RRFQAMTTOT)}$$

Where:

Total payment of SASM-procured capacity for Responsive Reserve by market

$$\text{RTPCRRAMTTOT}_{m} = \sum_{q} \text{RTPCRRAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for Responsive Reserve

$$\text{PCRRAMTTOT} = \sum_{q} \text{PCRRAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Responsive Reserve

$$\text{RRFQAMTTOT} = \sum_{q} \text{RRFQAMT}_{q}$$

Total payment of SASM procured capacity RRS Service by QSE

$$\text{RTPCRRAMTQSETOT}_{q} = \sum_{m} \text{RTPCRRAMT}_{q,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
RRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for Responsive Reserve for the hour.
RTPCRRAMTTOT $_{m}$	$	*Procured Capacity for Responsive Reserve Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Responsive Reserve, for the hour.
RTPCRRAMT $_{q,\,m}$	$	*Procured Capacity for Responsive Reserve Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Responsive Reserve, for the hour.
RRFQAMTTOT	$	*Responsive Reserve Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures on their Ancillary Service Supply Responsibilities for Responsive Reserve, for the hour.
RRFQAMT $_{q}$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Responsive Reserve, for the hour.
RTPCRRAMTQSETOT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount Total per QSE*—The total payments to a QSE in all SASM markets for the Ancillary Service Offers cleared for Responsive Reserve, for the hour.
PCRRAMT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount per QSE for DAM*—The DAM Responsive Reserve payment for QSE *q*, for the hour.
PCRRAMTTOT	$	*Procured Capacity for Responsive Reserve Amount Total in DAM*—The total of the DAM Responsive Reserve payments for all QSEs, for the hour.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(b) Each QSE's share of the net total costs for Responsive Reserve for the Operating Hour is calculated as follows:

$$\textbf{RRCOST}_{q} = \textbf{RRPR} * \textbf{RRQ}_{q}$$

Where:

$$\text{RRPR} = \text{RRCOSTTOT} / \text{RRQTOT}$$

$$\text{RRQTOT} = \sum_{q} \text{RRQ}_{q}$$

$$\text{RRQ}_{q} = \text{RRO}_{q} - \text{SARRQ}_{q}$$

$$\text{RRO}_{q} = \sum_{q} (\text{SARRQ}_{q} + \sum_{m} (\text{RTPCRR}_{q,\,m}) + \text{PCRR}_{q} - \text{RRRP}_{q} - \text{RRFQ}_{q}) * \text{HLRS}_{q} + \text{RRRP}_{q}$$

$$\text{SARRQ}_{q} = \text{DASARRQ}_{q} + \text{RTSARRQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
$RRCOST_{q}$	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for Responsive Reserve, for the hour.
RRPR	$/MW per hour	*Responsive Reserve Price*—The price for Responsive Reserve calculated based on the net total costs for Responsive Reserve, for the hour.
RRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for Responsive Reserve for the hour. See item (a) above.
RRQTOT	MW	*Responsive Reserve Quantity Total*—The sum of every QSE's portion of its Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
RRQ_{q}	MW	*Responsive Reserve Quantity per QSE*—The portion of QSE *q*'s Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
RRO_{q}	MW	*Responsive Reserve Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
$DASARRQ_{q}$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged Responsive Reserve quantity submitted by QSE *q* before 1000 in the Day-Ahead.
$RTSARRQ_{q}$	MW	*Self-Arranged Responsive Reserve Quantity per QSE for all SASMs*—The sum of all self-arranged Responsive Reserve quantities submitted by QSE *q* for all SASMs.
$RTPCRR_{q,m}$	MW	*Procured Capacity for Responsive Reserve per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Responsive Reserve, for the hour.
$RRFQ_{q}$	MW	*Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Responsive Reserve, for the hour.
$HLRS_{q}$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.3.
$RRRP_{q}$	MW	*Responsive Reserve Replacement per QSE per market*—The total Responsive Reserve capacity that was a portion of the Ancillary Service Supply Responsibility of QSE *q* but is replaced in a SASM for the hour.
$PCRR_{q}$	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total Responsive Reserve capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE for the hour.
$SARRQ_{q}$	MW	*Total Self-Arranged Responsive Reserve Quantity per QSE for all markets*—The sum of all self-arranged Responsive Reserve quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Responsive Reserve for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTRRAMT}_{q} = \mathbf{RRCOST}_{q} - \mathbf{DARRAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description

RTRRAMT $_q$	$	*Real-Time Responsive Reserve Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Responsive Reserve, for the hour.
RRCOST $_q$	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for Responsive Reserve, for the hour.
DARRAMT $_q$	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for Responsive Reserve, for the hour.
q	none	A QSE.

(4) For Non-Spin, if applicable:

(a) The net total costs for Non-Spin for a given Operating Hour is calculated as follows:

$$\textbf{NSCOSTTOT} = (-1) * (\sum_{m} (\textbf{RTPCNSAMTTOT}_{m}) + \textbf{PCNSAMTTOT} + \textbf{NSFQAMTTOT})$$

Where:

Total payment of SASM-procured capacity for Non-Spin by market

$$\text{RTPCNSAMTTOT}_{m} = \sum_{q} \text{RTPCNSAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for Non-Spin

$$\text{PCNSAMTTOT} = \sum_{q} \text{PCNSAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Non-Spin

$$\text{NSFQAMTTOT} = \sum_{q} \text{NSFQAMT}_{q}$$

Total payment of SASM procured capacity for Non-Spin by QSE

$$\text{RTPCNSAMTQSETOT}_{q} = \sum_{m} \text{RTPCNSAMT}_{q,\,m}$$

The above variables are defined as follows:

Variable	Unit	Description
NSCOSTTOT	$	*Non-Spin Cost Total*—The net total costs for Non-Spin for the hour.
RTPCNSAMTTOT $_m$	$	*Procured Capacity for Non-Spin Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
RTPCNSAMT $_{q,\,m}$	$	*Procured Capacity for Non-Spin Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
NSFQAMTTOT	$	*Non-Spin Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures on their Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
NSFQAMT $_q$	$	*Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility

Variable	Unit	Description
		for Non-Spin, for the hour.
RTPCNSAMTQSETOT $_q$	$	*Procured Capacity for Non-Spin Amount Total per QSE*—The total payments to a QSE in all SASM markets for the Ancillary Service Offers cleared for Non-Spin, for the hour.
PCNSAMT $_q$	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
PCNSAMTTOT	$	*Procured Capacity for Non-Spin Amount Total in DAM*—The total of the DAM Non-Spin payments for all QSEs for the hour.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(b) Each QSE's share of the net total costs for Non-Spin for the Operating Hour is calculated as follows:

$$\mathbf{NSCOST}_{q} = \mathbf{NSPR * NSQ}_{q}$$

Where:

$$\text{NSPR} = \text{NSCOSTTOT / NSQTOT}$$

$$\text{NSQTOT} = \sum_{q} \text{NSQ}_{q}$$

$$\text{NSQ}_{q} = \text{NSO}_{q} - \text{SANSQ}_{q}$$

$$\text{NSO}_{q} = \sum_{q} (\text{SANSQ}_{q} + \sum_{m} (\text{RTPCNS}_{q,\,m}) + \text{PCNS}_{q} - \text{NSRP}_{q} - \text{NSFQ}_{q}) * \text{HLRS}_{q} + \text{NSRP}_{q}$$

$$\text{SANSQ}_{q} = \text{DASANSQ}_{q} + \text{RTSANSQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
NSCOST $_q$	$	*Non-Spin Cost per QSE*—QSE *q*'s share of the net total costs for Non-Spin, for the hour.
NSPR	$/MW per hour	*Non-Spin Price*—The price for Non-Spin calculated based on the net total costs for Non-Spin, for the hour.
NSCOSTTOT	$	*Non-Spin Cost Total*—The net total costs for Non-Spin for the hour. See item (a) above.
NSQTOT	MW	*Non-Spin Quantity Total*—The sum of every QSE's portion of its Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
NSQ $_q$	MW	*Non-Spin Quantity per QSE*—The portion of QSE *q*'s Ancillary Service Obligation that is not self-arranged in either DAM or any SASM, for the hour.
NSO $_q$	MW	*Non-Spin Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASANSQ $_q$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE for DAM*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.

Variable	Unit	Description
RTSANSQ $_q$	MW	*Self-Arranged Non-Spin Quantity per QSE for all SASMs*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for all SASMs.
RTPCNS $_{q, m}$	MW	*Procured Capacity for Non-Spin per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Non-Spin, for the hour.
NSFQ $_q$	MW	*Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
HLRS $_q$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.3.
NSRP $_q$	MW	*Non-Spin Replacement per QSE per market*—The total Non-Spin capacity that was a portion of the Ancillary Service Supply Responsibility of QSE *q* but is replaced in a SASM for the hour.
PCNS $_q$	MW	*Procured Capacity for Non-Spin Service per QSE in DAM*—The total Non-Spin capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE for the hour.
SANSQ q	MW	*Total Self-Arranged Non-Spin Supplied Quantity per QSE for all markets*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	A SASM for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Non-Spin for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\textbf{RTNSAMT}_{q} \quad = \quad \textbf{NSCOST}_{q} - \textbf{DANSAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTNSAMT $_q$	$	*Real-Time Non-Spin Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Non-Spin, for the hour.
NSCOST $_q$	$	*Non-Spin Cost per QSE*—QSE *q*'s share of the net total costs for Non-Spin, for the hour.
DANSAMT $_q$	$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin, for the hour.
q	none	A QSE.

ERCOT Nodal Protocols

Section 7: Congestion Revenue Rights

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's]() Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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7 CONGESTION REVENUE RIGHTS

7.1 Function of Congestion Revenue Rights

(1) A Congestion Revenue Right (CRR) is a financial instrument that entitles the CRR Owner to be charged or to receive compensation for congestion rents that arise when the ERCOT Transmission Grid is congested in the Day-Ahead Market (DAM) or in Real-Time. CRRs do not represent a right to receive, or obligation to deliver, physical energy. Most CRRs are tradable in the CRR Auction, in the DAM, or bilaterally, as described in more detail in this Section.

(2) CRRs may be acquired as follows:

(a) CRR Auction – ERCOT shall conduct periodic auctions to allow eligible CRR Account Holders to acquire CRRs. The auction also allows CRR Owners an opportunity to sell CRRs that they hold.

(b) PCRR Allocations – ERCOT shall allocate CRRs (known as Preassigned Congestion Revenue Rights or PCRRs) to eligible Municipally Owned Utilities and Electric Cooperatives under Section 7.4, Allocation of Preassigned Congestion Revenue Rights.

(c) McCamey Area Flowgate Rights Allocations – ERCOT shall allocate McCamey Area Flowgate Rights (MCFRIs), which are a type of Flowgate Right (FGR), to eligible Market Participants under Section 7.7.3, Allocation of McCamey Flowgate Rights (MCFRIs).

(d) Bilateral Market – Any CRR Account Holder may trade PTP Options, PTP Obligations, and FGRs bilaterally. PTP Options with Refund and PTP Obligations with Refund are not tradable, except in the DAM. Bilateral trading may be done privately or through ERCOT. ERCOT shall facilitate trading on the MIS Secure Area of existing CRRs between CRR Account Holders, subject to credit requirements. ERCOT shall settle CRRs with the CRR Account Holder shown on ERCOT records.

(e) DAM – Any QSE that is also a CRR Account Holder may bid for PTP Obligations in the DAM.

(3) Each CRR is one of these types:

(a) Point-to-Point (PTP) Option, some of which may be PCRRs;

(b) PTP Obligation, some of which may be PCRRs;

(c) PTP Option with Refund, all of which are PCRRs;

(d) PTP Obligation with Refund, all of which are PCRRs; and

(e) Flowgate Right (FGR), including a MCFRI.

7.2 Characteristics of Congestion Revenue Rights

Each CRR has the following characteristics:

(a) Quantities are measured in MWs with granularity of tenths of MWs (0.1 MW);

(b) A duration of one hour;

(c) An ability to be fully tradable financial instruments except in specified time-of-use blocks for a PTP Option with Refund and a PTP Obligation with Refund; and

(d) A designated source (injection point) that is a Settlement Point and a designated sink (withdrawal point) that is a different Settlement Point, except for an FGR, which has a designated directional network element, or a bundle of directional network elements, instead.

7.2.1 CRR Naming Convention

The appropriate TAC subcommittee shall establish a task force that is open to Market Participants, comprised of technical experts, to develop a naming convention for CRRs consistent with the requirements of the Protocols. The naming convention must be approved by TAC before implementation.

7.3 Types of Congestion Revenue Rights to Be Auctioned

(1) ERCOT shall auction the following types of CRRs:

(a) PTP Options;

(b) PTP Obligations; and

(c) FGRs that are offered by CRR Account Holders.

(2) PTP Options are evaluated hourly in each CRR Auction as the positive power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points in the quantity represented by the CRR bid or offer (MW), excluding all negative flows on all directional network elements.

(3) PTP Obligations are evaluated hourly in each CRR Auction as the positive and negative power flows on all directional network elements created by the injection and withdrawal at the specified source and sink points of the quantity represented by the CRR bid or offer (MW).

(4) PTP Options can only result in payments from ERCOT to the CRR Owner of record. A PTP Obligation may result in either a payment or a charge to the CRR Owner of record.

(5) FGRs are evaluated in each CRR Auction as the positive power flows represented by the quantity of the CRR bid or offer (MW) on a flowgate, (i.e., predefined directional network element or a predefined bundle of directional network elements).The flowgates on which FGRs are offered by ERCOT are specified in Section 7.3.1.2, Defined Flowgates.

(6) CRRs must be auctioned in the following Time-Of-Use (TOU) blocks (having the same MW amount for each hour within the block):

(a) 5x16 blocks for hours ending 0700-2200, Monday through Friday (excluding NERC holidays), in one-month strips;

(b) 2x16 blocks for hours ending 0700-2200, Saturday and Sunday, and NERC holidays in one-month strips;

(c) 7x8 blocks for hours ending 0100-0600 and hours ending 2300-2400 Sunday through Saturday, in one-month strips; and

(7) The CRR blocks described in paragraph (6) above must be auctioned simultaneously in the annual CRR Auctions, in which capacity is made available for the next two years.

(8) CRR Auction Bids and PCRR nominations must specify a TOU block.

7.3.1 Flowgates

7.3.1.1 Process for Defining Flowgates

Flowgates where ERCOT offers FGRs may only be created by an amendment to Section 7.3.1.2, Defined Flowgates. ERCOT shall post the list of all flowgates available for FGRs on the MIS Public Area. If there is any change in the designation of flowgates, ERCOT shall provide notice to all Market Participants as soon as practicable.

7.3.1.2 Defined Flowgates

McCamey Area flowgates are the only flowgates where FGRs are available in ERCOT as specified in Section 7.7, Congestion Management in McCamey Area.

7.4 Allocation of Preassigned Congestion Revenue Rights

Under this Section, ERCOT shall allocate a portion of the Congestion Revenue Rights to certain Market Participants.

7.4.1 PCRR Allocation Eligibility

(1) PCRRs are available to be allocated to Non-Opt In Entities (NOIEs) that choose to apply for those rights and that:

(a) Own or have a long-term (greater than five years) contractual commitment that was entered into before September 1, 1999 for annual capacity and energy from specific Generation Resources; or

(b) Have a long-term (greater than five years) allocation from the federal government for annual capacity and energy produced at a federally-owned hydroelectric Generation Resource, and that allocation was in place prior to September 1, 1999.

(2) A Municipally Owned Utility or Electric Cooperative may no longer receive allocated PCRRs after they opt into competition, with the exception of South Texas Electric Cooperative (STEC). STEC may be allocated PCRRs for up to three years after the date it enters into competition.

7.4.2 PCRR Allocation Terms and Conditions

ERCOT shall allocate CRRs under the following terms and conditions:

(a) ERCOT shall conduct studies to evaluate whether the nominated PCRRs comply with feasibility constraints using the simultaneous feasibility test described in Section 7.5.5.4, Simultaneous Feasibility Test. A PCRR nomination is a request for one-month strips of a NOIE-specified CRR type for amounts and blocks specified by the NOIE for each month of the next auction following the allocation of PCRRs as described in paragraph (c) below. The SFT evaluation to determine the feasible PCRR allocation amount for each month being evaluated uses 100% of that month's expected network topology, which may result in different amounts allocated in different months. If the SFT evaluation indicates that the nominated PCRR amounts are not feasible, then ERCOT shall proportionately reduce the requested PCRRs by their Impact Ratio on violated constraints. The "Impact Ratio" is the fraction a particular PCRR's impact relative to the impact of all PCRRs in the same direction on a violated constraint. The nominated PCRR amounts for the annual CRR auction period and for each monthly CRR auction period, adjusted for infeasibilities in the SFT evaluation if required, determines the allocated PCRR amount. The price that a NOIE must pay for an allocated PCRR, including any PCRR allocated under paragraph (d) below, is based on the corresponding CRR clearing price in the next auction following the allocation of PCRRs. The invoicing and payment for all allocated PCRRs follow the same process and timeline as the invoicing and payment of CRR bids cleared in the next auction following the allocation of PCRRs.

(b) ERCOT shall allocate all PCRRs in quantities truncated to the nearest tenth MW (0.1 MW).

(c) Each eligible NOIE may nominate and ERCOT shall allocate to that NOIE as so nominated, subject to the limitation of paragraph (a) above, PCRRs up to 100% of the net unit capacity (or contractual amount) for each eligible Resource, except as noted below in paragraph (d).

(i) Until the first annual CRR Auction, NOIEs must nominate PCRRs for the month before each monthly auction. Nominations must be received at ERCOT no later than 15 Business Days prior to the commencement of the monthly auction for the one-month term which the CRRs being auctioned are effective. ERCOT shall allocate PCRRs to the NOIE no later than ten Business Days prior to the corresponding monthly auction.

(ii) For the first annual CRR Auction, the NOIE must nominate PCRRs for each month of the following two years before the first annual CRR Auction. Nominations must be received at ERCOT no later than 30 Business Days prior to the commencement of the annual auction. ERCOT shall allocate PCRRs to the NOIE no later than 25 Business Days prior to the annual auction.

(iii) For all subsequent annual CRR Auctions, the NOIE must nominate PCRRs for each month of the second year before each annual CRR Auction. Nominations must be received at ERCOT no later than 30 Business Days prior to the commencement of the annual auction. ERCOT shall allocate PCRRs to the NOIE no later than 25 Business Days prior to the annual auction.

(d) If at the time of the annual CRR Auction, ERCOT determines that PCRR nominations are not feasible, resulting in proportionally reduced PCRR allocations, then prior to each subsequent monthly CRR Auction, ERCOT shall re-evaluate the full nomination and allocate additional PCRRs, if feasible, up to the nomination amount.

(e) A NOIE must designate whether to accept the refund option or the capacity option for its eligible non-solid fuel and non-combined-cycle Resources before the allocation of PCRRs. These options are described in items (i) and (ii) below. NOIEs, or a group of NOIEs linked by common pre-1999 power supply arrangements, which had a 2003 NOIE peak Load in excess of 2,300 MW must use the capacity option (ii) for their eligible non-solid-fuel and non-combined-cycle Resources:

(i) Refund option – The eligible NOIE may nominate up to 100% of the lesser of the net unit capacity or contractual amount for those Resources. The eligible NOIE shall refund to ERCOT any congestion revenues received above those congestion revenues flowing to the NOIE for its Output Schedule of the Resource at the PCRR source. PCRR settlement will reflect the MW value of the Output Schedule of the Resource at the PCRR source, regardless of what MW value of actual output occurred during that interval if that change in output is in response to Dispatch Instructions. The refund for any Settlement Interval is equal to the difference between the PCRR MW amount and the time-weighted average of the Output Schedules of the Resource at the PCRR source multiplied by the value of that PCRR. PCRRs allocated under the refund option are not transferable and may only be used by the NOIE to which they are allocated.

(ii) Capacity option – The eligible NOIE may nominate up to 100% of the lesser of the net unit capacity or contractual amount for those Resources at a capacity factor no greater than 40% over each calendar year . ERCOT shall allocate PCRRs in accordance with the NOIE nominations subject to the SFT.

(A) Before the applicable CRR Auctions, the NOIE must nominate the months (designating CRR amounts as defined by the criteria specified in item (6) of Section 7.3, Types of Congestion Revenue Rights) for which it will use its PCRRs (i.e., the NOIE may shape the PCRRs representing up to 100% of the capacity for each Resource at a capacity factor no greater than 40% over each calendar year).

(B) If a Resource eligible for PCRRs is shut down due to a Force Majeure Event, then, to the extent feasible, the NOIE may reallocate its PCRRs across its PCRR-eligible facilities before the next CRR Auction. This change is effective no later than the date of the next CRR Auction, and the redesignation may be requested for each monthly auction during the Force Majeure Event. Any price difference in the reconfigured rights must be paid by (or paid to) the NOIE.

(f) ERCOT shall allocate the total nominated capacity for each eligible NOIE to the Load of that NOIE in reasonable proportion to the Load served by the NOIE in each Load Zone. For this allocation, ERCOT shall use the aggregated monthly load data from the corresponding prior 12 months.

(g) The CRR type, either PTP Option, PTP Obligation, or a combination, must be specified by the eligible NOIE before the PCRR allocation and is binding for purchase. Once the allocation process is complete, the eligible NOIE may not change the CRR type.

(h) After the allocation process, and the subsequent applicable CRR Auction, PCRRs other than those described in item (iii) below must be priced as a percentage of the applicable CRR Auction clearing price for the applicable CRR, as follows:

(i) PTP Option PCRRs:

(A) **Nuclear, coal, lignite or combined-cycle Resources:** 10% of the applicable CRR Auction clearing prices;

(B) **Gas steam Resources:** 15% of the applicable CRR Auction clearing prices; or

(C) **Hydro, wind, simple cycle, or other Resources not included in (A) or (B):** 20% of the applicable CRR Auction clearing prices.

(ii) PTP Obligation PCRRs:

(A) **Nuclear, coal, lignite or combined-cycle Resources**: 5% of the applicable CRR Auction clearing price if it is positive; 100% of the applicable CRR Auction clearing price if it is negative;

(B) **Gas steam Resources:** 7.5% of the applicable CRR Auction clearing price if such price is positive; 100% of the applicable CRR Auction clearing price if it is negative; or

(C) **Hydro, wind, simple cycle, or other Resources not included in (A) or (B):** 10% of the applicable CRR Auction clearing prices if it is positive; 100% of the applicable CRR Auction clearing prices if it is negative.

(iii) For a NOIE that has chosen the refund option, the allocated number of PCRRs for Resources other than solid-fuel and combined-cycle Resources are provided at no charge.

(i) PCRRs shall not be able to be bilaterally traded through ERCOT systems prior to the completion of the CRR Auction used to determine their value.

7.5 CRR Auctions

7.5.1 Nature and Timing

(1) The CRR Auction auctions the available network capacity of the ERCOT Transmission System not allocated as described in Section 7.4, Allocation of Preassigned Congestion Revenue Rights and in Section 7.7.3, Allocation of McCamey Flowgate Rights (MCFRIs), or sold in a previous auction. The CRR Auction also allows CRR Owners an opportunity to offer for sale CRRs that they hold. Each annual and monthly CRR Auction allows for the purchase of CRR products as described in Section 7.3, Types of Congestion Revenue Rights to Be Auctioned, paragraph (6) in one-month strips and allows for the reconfiguration of all CRR blocks that were previously awarded. Monthly CRR Auctions will include products for the next month only.

(2) The CRR Network Model must be based on, but is not the same as, the Network Operations Model. The CRR Network Model must, to the extent practicable, include the same topology, contingencies, and operating procedures as used in the Network Operations Model as reasonably expected to be in place for each month. The expected network topology used in the CRR Network Model for any month must include all outages from the Outage Scheduler and identified by ERCOT staff as expected to have a significant impact upon transfer capability during the month. These outages included in the CRR Network Model shall be posted on the MIS Secure Area consistent with model posting requirements by ERCOT with accompanying cause and duration information, as indicated in the Outage Scheduler. Transmission system upgrades and changes must be accounted for in the CRR Network Model for CRR Auctions held after the month in which the element is placed into service.

(a) ERCOT shall use Dynamic Ratings in the CRR Network Model as required under Section 3.10.8, Dynamic Ratings.

(b) The CRR Network Model must use the peak Load conditions of the month being modeled.

(c) ERCOT's criteria for determining if an Outage should be in the CRR Network Model shall be in accordance with these Protocols and described in the ERCOT Operating Guides.

(3) ERCOT shall model bids and offers into the CRR Auction as flows based on the MW offer and defined source and sink. When the Simultaneous Feasibility Test (SFT) is run, the model must weight the Electrical Buses and Hub Buses included in a Hub or Load Zone appropriately to determine the system impacts of the CRRs.

(a) To distribute injections and withdrawals to buses within a Hub, ERCOT shall use distribution factors specified in Section 3.5.2, Hub Definitions.

(b) To distribute injections and withdrawals to Electrical Buses in Load Zones, ERCOT shall use the Load-weighted distribution factors for On-Peak Hours in each Load Zone from the planning cases (for the same period) for monthly CRR Auctions (or for the monthly models used in an annual CRR Auction). If monthly planning cases do not exist, ERCOT shall use the Load-weighted distribution factors for On-Peak Hours in each Load Zone from the appropriate seasonal planning case.

(4) ERCOT shall conduct CRR Auctions with the frequency, on the dates, and for the terms specified as follows:

(a) PTP Options, PTP Obligations, and MCFRIs in monthly auctions for one-month terms beginning with the month prior to the Texas Nodal Market Implementation Date;

(b) ERCOT shall conduct a monthly CRR Auction during the month preceding the month during which the CRRs being auctioned are effective. ERCOT shall publish a calendar of relevant auction dates each year for the following year's activities.

(c) Six monthly CRR Auctions must be completed prior to initiation of the first annual CRR Auction. If six monthly CRR Auctions are completed prior to October 1, then CRR Options, MCFRIs and Board-approved PTP Obligations will be auctioned for the balance of the current calendar year.

(d) After the completion of at least six monthly CRR Auctions ERCOT shall conduct an annual CRR Auction for CRR Options, MCFRIs and Board-approved PTP Obligations commencing during October for the two-year period that starts on the immediately following January 1.

(5) ERCOT shall auction the following products:

(a) In each monthly CRR Auction: one-month strips of PTP Options, PTP Obligations, and MCFRIs; and

(b) In each annual CRR Auction:

(i) PTP Options in one-month strips, any specified consecutive monthly strips within the same calendar year, and annual strips;

(ii) PTP Obligations in one-month strips for one-month terms until the ERCOT Board approves the offering of PTP Obligations for specified source Settlement Points and sink Settlement Points for terms longer than one month; and

(iii) MCFRIs in one-month strips, any specified consecutive monthly strips within the same calendar year, and annual strips.

(6) ERCOT shall offer network capacity for two years in each annual CRR Auction equal to the difference between (a) and (b) :

(a) For each month, the expected network topology for that month of the first year in the CRR Network Model scaled down to 55% for the first year and 15% for the second year; and

(b) All outstanding CRRs that were previously awarded or allocated for the corresponding months in each year scaled to 55% for the first year and 15% for the second year.

(7) ERCOT shall offer network capacity for the monthly CRR Auction equal to the difference between:

(a) The expected transmission network topology in the CRR Network Model of the month for which the CRRs are effective scaled down to 90%; and

(b) All outstanding CRRs that were previously awarded or allocated for the month.

7.5.2 CRR Auction Offers and Bids

(1) To submit bids or offers into a CRR Auction, an Entity must become a CRR Account Holder and satisfy financial assurance criteria required to participate, under Section 16.8, Registration and Qualification of Congestion Revenue Rights Account Holders.

(2) No later than six months prior to the Texas Nodal Market Implementation Date, ERCOT shall report to TAC about whether a limit on bid volume or a nominal transaction charge for each bid submitted would benefit the auction process. Recommendations from TAC must be approved by the ERCOT Board and may be implemented without further revision to these Protocols.

7.5.2.1 CRR Auction Offer Criteria

(1) A CRR Auction Offer indicates a willingness to sell CRRs at the auction clearing price, if it equals or exceeds the Minimum Reservation Price. It must be submitted by a CRR Account Holder and must include the following:

(a) The name of the CRR Account Holder;

(b) The unique identifier for each CRR being offered, which must include the single type of CRR being offered;

(c) The source Settlement Point and the sink Settlement Point or name of flowgate for the block of CRRs being offered;

(d) The month for which the block of CRRs is being offered, including block designation except that a 7x24 block may not be designated;

(e) The quantity of CRRs in MW, which must be the same for each hour within the block, for which the Minimum Reservation Price is effective; and

(f) A dollars per CRR (i.e. dollars per MW per hour) for the Minimum Reservation Price.

(2) The CRR Account Holder may submit a self-imposed auction-wide credit limit, if desired.

(3) A CRR Account Holder can only offer to sell one-month strips of CRRs for which it is the CRR Owner of record at the time of the offer.

(4) An offer to sell an FGR must specify the name of a flowgate as defined in Section 7.3.1, Flowgates.

(5) A CRR offer for a specified MW quantity of CRRs constitutes an offer to sell a quantity of CRRs equal to or less than the specified quantity. A CRR offer may not specify a minimum quantity of MW that the CRR Account Holder wishes to sell.

7.5.2.2 CRR Auction Offer Validation

(1) A valid CRR Auction Offer is a CRR Auction Offer that ERCOT has determined meets the criteria listed in Section 7.5.2.1, CRR Auction Offer Criteria.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any CRR Account Holder submitting a CRR Auction Offer to view its valid CRR Auction Offers.

(3) As soon as practicable, ERCOT shall notify each CRR Account Holder of any of its CRR Auction Offers that are invalid. The CRR Account Holder may correct and resubmit any invalid CRR Auction Offer, if within the appropriate auction timeline.

7.5.2.3 CRR Auction Bid Criteria

(1) A CRR Auction Bid indicates a willingness to buy CRRs at the auction clearing price, if it is equal to or less than the Not-to-Exceed Price. It must be submitted by a CRR Account Holder and must include the following:

(a) The name of the CRR Account Holder;

(b) The single type of CRR being bid;

(c) The source Settlement Point and the sink Settlement Point or name of flowgate for the block of CRRs being bid;

(d) The month for which the block of CRRs is being bid, including block designation;

(e) The quantity of CRRs in MW, which must be the same for each hour within the block, for which the Not-to-Exceed Price is effective; and

(f) A dollars per CRR (i.e. dollars per MW per hour) for the Not-to-Exceed Price.

(2) The CRR Account Holder may submit a self-imposed auction-wide credit limit, if desired.

(3) A bid to buy a PTP Option or Flowgate Right cannot specify a negative Not-to-Exceed Price. A bid to buy a PTP Obligation can specify a negative Not-to-Exceed Price.

(4) A bid to buy an FGR must specify the name of a flowgate defined in Section 7.3.1, Flowgates.

(5) A CRR bid for a specified MW quantity of CRRs constitutes a bid to buy a quantity of CRRs equal to or less than the specified quantity. A CRR bid may not specify a minimum quantity of MW that the CRR Account Holder wishes to buy.

7.5.2.4 CRR Auction Bid Validation

(1) A valid CRR Auction Bid is a CRR Auction Bid that ERCOT has determined meets the criteria listed in Section 7.5.2.3, CRR Auction Bid Criteria.

(2) ERCOT shall continuously display on the MIS Certified Area information that allows any CRR Account Holder submitting a CRR Auction Bid to view its valid CRR Auction Bids.

(3) As soon as practicable, ERCOT shall notify each CRR Account Holder of any of its CRR Auction Bids that are invalid. The CRR Account Holder may correct and resubmit any invalid CRR Auction Bid, if within the appropriate auction timeline.

7.5.3 ERCOT Responsibilities

(1) ERCOT shall:

- (a) Manage the qualification and registration of eligible CRR Account Holders;
- (b) Post calendar of CRR Auctions;
- (c) Initiate, direct, and oversee the CRR Auction;
- (d) Post CRR Auction results;
- (e) Maintain a record of the CRRs;
- (f) Provide a mechanism to record CRR bilateral transactions;
- (g) Determine CRR Auction settlement and distribute auction revenues;
- (h) Keep, under the ERCOT data retention policy, all information and tools necessary to reproduce CRR calculations; and
- (i) Post CRR Network Model of the effective month of the auction on the MIS Secure Area, before each CRR Auction:
  - (i) For monthly auctions the model shall be posted no later than 10 Business Days before the auction.
  - (ii) For annual auctions the model shall be posted no later than 20 Business Days before the annual auction.

(2) ERCOT shall use the CRR Network Model as defined in Section 3.10.3, CRR Network Model.

(3) ERCOT shall develop and maintain a CRR guide to help Market Participants with the CRR program.

(4) Before each auction, ERCOT shall establish a credit limit under Section 16, Registration and Qualification of Market Participants, that is imposed in the CRR Auction.

7.5.3.1 Data Transparency

(1) Following each CRR Auction, ERCOT shall record and make available to each CRR Account Holder on the MIS Certified Area the following information for each CRR awarded in, sold in, or allocated before, the CRR Auction to the specific CRR Account Holder:

(a) Unique identifier of each CRR;

(b) Type of CRR (PTP Option, PTP Obligation, PTP Option with Refund, PTP Obligation with Refund, MCFRIs or other FGRs);

(c) Clearing price and, if applicable, the PCRR pricing factor of each CRR;

(d) Except for FGRs, the source and sink of each CRR; and

(e) FGR identity and direction;

(f) The date and time-of-use block for which the CRR is effective; and

(g) Total MW of each PTP pair of CRR, awarded, sold or allocated, or total MW for each flowgate, awarded, sold or allocated.

(2) Following each CRR Auction, ERCOT shall post to the MIS Public Area the following information for all outstanding CRRs following this auction:

(a) PTP Options and PTP Options with Refund – the source and sink , and total MWs;

(b) PTP Obligations and PTP Obligations with Refund – the source and sink and total MWs;

(c) FGRs – the identity of each directional flowgate, and the magnitude of positive flow (MW) on each directional network element represented by each flowgate;

(d) The identities of the CRR Account Holders that were awarded or allocated CRRs in or before the CRR Auction;

(e) The clearing prices for each strip of CRR blocks awarded in the CRR Auction;

(f) The identity and post contingency flow of each binding directional element based on the CRR Network Model used in the CRR Auction; and

(g) All CRR Auction Bids and CRR Auction Offers, without identifying the name of the CRR Account Holder that submitted the bid or offer.

7.5.3.2 Auction Notices

(1) Not less than 20 days before each annual CRR Auction and not less than 10 days before each monthly CRR Auction, ERCOT shall post the following to the MIS Public Area:

(a) For the CRR Auction, number and type (PTP Options or PTP Obligations) of CRRs previously awarded or allocated for each appropriate month, including the source and sink for each such CRR;

(b) For the CRR Auction, number of MCFRIs that have been previously awarded or allocated for each appropriate month, including the flowgate for each such MCFRI;

(c) McCamey Area flowgate limits and the affected Transmission Elements used to derive those limits;

(d) Deadline for CRR Account Holders to satisfy financial requirements to participate in the auction;

(e) Specifications for the equipment and interfaces necessary to participate in the CRR Auction;

(f) Date and time by which CRR Auction Bids and CRR Auction Offers in the CRR Auction must be submitted;

(g) Bid and offer format; and

(h) Any other relevant information of commercial significance to CRR Account Holders.

7.5.4 CRR Account Holder Responsibilities

(1) Eligible CRR Account Holders may submit CRR Auction Bids and CRR Auction Offers.

(2) Each CRR Account Holder must maintain adequate credit for its CRR holdings, and CRR Auction participation requirements, as described in Section 16, Registration and Qualification of Market Participants.

7.5.5 Auction Clearing Methodology

7.5.5.1 Creditworthiness

The CRR Auction system prevents a CRR Account Holder from being awarded bids and offers that exceed the lesser of the CRR Account Holder's self-imposed credit limit or the credit limit as prescribed in Section 16.11.4.6.1, Credit Requirements for CRR Auction Participation.

7.5.5.2 Disclosure of CRR Ownership

ERCOT shall post monthly, by the fifth Business Day of the month, on the MIS Public Area CRR ownership of record for each source and sink pair and each flowgate: the identities of the CRR Account Holders, type of CRR held by that account holder, and total MWs held by that account holder.

7.5.5.3 Auction Process

(1) The auction must be a single-round, simultaneous auction for selling the CRRs available for all auction products, with the following steps:

(a) ERCOT shall enter into the CRR Auction engine model a credit constraint for each Counter-Party. A Counter-Party's CRR Auction credit limit is equal to the lesser of the credit limit as determined in Section 16.11.4.6.1, Credit Requirements for CRR Auction Participation, or, if provided, the Counter Party's self-imposed CRR Auction credit limit. The credit constraint for each Counter-Party ensures that the following sum for all of the Counter-Party's CRR Account Holders is less than or equal to the Counter-Party's CRR Auction credit limit:

(i) all awarded CRR Auction Bids multiplied by the absolute value of the corresponding bid price; plus

(ii) all awarded CRR Auction Offers with negative offer prices multiplied by the absolute value of their corresponding offer price; plus

(iii) the additional credit requirement for all awarded PTP Obligations.

(b) ERCOT shall award CRRs in quantities truncated to the nearest tenth MW (0.1 MW).

(c) The CRR Clearing Price is equal to the corresponding Shadow Price for that CRR product.

(d) When a CRR Account Holder is awarded CRRs as a result of a CRR Auction, the CRRs do not become the property of the winning CRR Account Holder, and the CRRs may not be placed in their CRR accounts, until the CRR Invoices have been paid in full.

(e) When a CRR Account Holder sells PTP Obligations as a result of an auction at a negative price, the CRR Account Holder is not relieved of the PTP Obligations until the CRR Invoices have been paid in full.

(2) ERCOT shall use a linear programming auction engine model for each CRR Auction that evaluates all CRR Auction Bids and CRR Auction Offers submitted, and selects a combination of CRR Auction Bids and CRR Auction Offers that:

(a) Makes the solution simultaneously feasible within the limits of the ERCOT network capability over the auction term; and

(b) Maximizes the objective function, which is equal to the total economic value (as expressed in the CRR Auction Bids) of the awarded CRR Auction Bids, less the total economic cost (as expressed in CRR Auction Offers) of the awarded CRR Auction Offers, while observing all applicable constraints.

(3) The CRR Network Model must, to the extent practicable, reflect the continuous and post-contingency system operating limits and operational procedures (i.e., Special Protection Systems and Remedial Action Plans) in the Network Operations Model used by ERCOT during Real-Time Operations, as discussed below in Section 7.5.5.4, Simultaneous Feasibility Test.

(4) Once a CRR Auction is complete, ERCOT shall archive and keep the CRR Auction system and all models used to finalize the CRR Auction results under ERCOT's data retention policy as that policy applies to data that may be needed to resolve requests for billing adjustments under applicable billing adjustment procedures.

7.5.5.4 Simultaneous Feasibility Test

(1) The Simultaneous Feasibility Test (SFT) is a market feasibility test that confirms that the transmission system can support the awarded set of CRRs during normal system conditions, assuming that the Network Operations Model updated with Real-Time network topology is the same as that modeled (for the CRR Auction), while observing all security constraints.

(2) The SFT uses a DC power-flow model to model the effect of CRR Auction bids and offers on the expected system network topology during the auction term. SFT is not a system reliability test and is not intended to model actual system operating conditions. SFTs are run during the determination of the winning bids and offers for the CRR Auction.

(3) Inputs to the SFT model include:

(a) CRR bids and offers for the auction;

(b) All previously awarded or allocated CRRs for the study period;

(c) Transmission line outage schedules;

(d) Expected configuration of Transmission Facilities, adjusted for oversold CRRs, as specified in paragraph (e) below;

(e) Increased capacity of each element that has been oversold in prior CRR Auctions and CRR allocations to exactly match the amount of CRRs that have been sold or allocated on that element (this ensures the feasibility of the CRR Auction);

(f) Thermal operating limits (including estimates for Dynamic Ratings) for transmission lines;

(i) for the annual auction ERCOT shall use Dynamic Ratings based on a historical analysis of the maximum peak-hour temperatures for the previous 10 years; and

(ii) for the monthly auction ERCOT shall use Dynamic Ratings for the maximum peak-hour temperature forecast for the month;

(g) Voltage and stability limits that are valid for the study period converted to thermal limits;

(h) ERCOT Transmission Grid pre- and post-contingency ratings;

(i) All Transmission Element contingencies expected to be used by ERCOT in Real-Time Operations; and

(j) RAPs and SPSs.

7.5.6 CRR Auction Settlements

7.5.6.1 Payment of an Awarded CRR Auction Offer

(1) ERCOT shall pay each CRR Account Holder of its PTP Obligation offers awarded in each CRR Auction. The payment for each source and sink pair for a given Operating Hour is calculated as follows:

$$\mathbf{OBLSAMT}_{\,crrh,\,(j,\,k),\,a} = \mathbf{(-1) * OBLPR}_{\,(j,\,k),\,a}\mathbf{\,*\,OBLS}_{\,crrh,\,(j,\,k),\,a}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
OBLSAMT $_{crrh, (j, k), a}$	$	*PTP Obligation Sale Amount per CRR Account Holder per source and sink pair per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
OBLPR $_{(j, k), a}$	$/MW	*PTP Obligation Price per source and sink pair per CRR Auction*—The clearing

	per hour	price of a PTP Obligation with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
OBLS $_{crrh, (j, k), a}$	MW	*PTP Obligation Sale per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *ccrh*'s PTP Obligation offers associated with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

(2) ERCOT shall pay each CRR Account Holder of its PTP Option offers awarded in each CRR Auction. The payment for each source and sink pair for a given Operating Hour is calculated as follows:

$$\textbf{OPTSAMT}_{\,crrh,\,(j,\,k),\,a} = \textbf{(-1) * OPTPR}_{\,(j,\,k),\,a}\,\textbf{* OPTS}_{\,crrh,\,(j,\,k),\,a}$$

The above variables are defined as follows:

Variable	Unit	Definition
OPTSAMT $_{crrh, (j, k), a}$	$	*PTP Option Sale Amount per CRR Account Holder per source and sink pair per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
OPTPR $_{(j, k), a}$	$/MW per hour	*PTP Option Price per source and sink pair per CRR Auction*—The clearing price of a PTP Option with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
OPTS $_{crrh, (j, k), a}$	MW	*PTP Option Sale per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *ccrh*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

(3) ERCOT shall pay each CRR Account Holder of its FGR offers awarded in each CRR Auction. The payment for each flowgate for a given Operating Hour is calculated as follows:

$$\textbf{FGRSAMT}_{\,crrh,\,f,\,a} = \textbf{(-1) * FGRPR}_{\,f,\,a}\,\textbf{* FGRS}_{\,crrh,\,f,\,a}$$

The above variables are defined as follows:

Variable	Unit	Definition
FGRSAMT $_{crrh, f, a}$	$	*Flowgate Right Sale Amount per CRR Account Holder per flowgate per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total FGR offers associated with FGR *f* awarded in CRR

		Auction *a*, for the hour.
FGRPR $_{f, a}$	\$/MW per hour	*Flowgate Right Price per flowgate per CRR Auction*—The clearing price of FGR *f* in CRR Auction *a*, for the hour.
FGRS $_{crrh, f, a}$	MW	*Flowgate Right Sale per CRR Account Holder per flowgate per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *ccrh*'s FGR offers associated with FGR *f* awarded in CRR Auction *a*, for the hour.
crrh	none	A CRR Account Holder.
f	none	An FGR.
a	none	A CRR Auction.

7.5.6.2 Charge of an Awarded CRR Auction Bid

(1) ERCOT shall charge each CRR Account Holder of its PTP Obligation bids awarded in each CRR Auction. The charge for each source and sink pair for a given Operating Hour is calculated as follows:

$$\textbf{OBLPAMT}_{\,crrh,\,(j,\,k),\,a} \quad = \quad \textbf{OBLPR}_{\,(j,\,k),\,a} \textbf{ * OBLP}_{\,crrh,\,(j,\,k),\,a}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
OBLPAMT $_{crrh, (j, k), a}$	\$	*PTP Obligation Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
OBLPR $_{(j, k), a}$	\$/MW per hour	*PTP Obligation Price per source and sink pair per CRR Auction*—The clearing price of a PTP Obligation with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
OBLP $_{crrh, (j, k), a}$	MW	*PTP Obligation Purchase per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *ccrh*'s PTP Obligation bids associated with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

(2) ERCOT shall charge each CRR Account Holder of its PTP Option bids awarded in each CRR Auction. The charge for each source and sink pair for a given Operating Hour is calculated as follows:

$$\textbf{OPTPAMT}_{\,crrh,\,(j,\,k),\,a} \quad = \quad \textbf{OPTPR}_{\,(j,\,k),\,a} \textbf{ * OPTP}_{\,crrh,\,(j,\,k),\,a}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**

Variable	Unit	Definition
OPTPAMT $_{crrh, (j, k), a}$	$	*PTP Option Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
OPTPR $_{(j, k), a}$	$/MW per hour	*PTP Option Price per source and sink pair per CRR Auction*—The clearing price of a PTP Option with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
OPTP $_{crrh, (j, k), a}$	MW	*PTP Option Purchase per CRR Account Holder per source and sink pair per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *ccrh*'s PTP Option bids associated with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.

(3) ERCOT shall charge each CRR Account Holder of its flowgate bids awarded in each CRR Auction. The charge for each flowgate for a given Operating Hour is calculated as follows:

$$\textbf{FGRPAMT}_{\ crrh,\, f,\, a} = \textbf{FGRPR}_{\ f,\, a} \; \textbf{*} \; \textbf{FGRP}_{\ crrh,\, f,\, a}$$

The above variables are defined as follows:

Variable	Unit	Definition
FGRPAMT $_{crrh, f, a}$	$	*Flowgate Right Purchase Amount per CRR Account Holder per flowgate per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total FGR bids associated with FGR *f* awarded in CRR Auction *a*, for the hour.
FGRPR $_{f, a}$	$/MW per hour	*Flowgate Right Price per flowgate per CRR Auction*—The clearing price of FGR *f* in CRR Auction *a*, for the hour.
FGRP $_{crrh, f, a}$	MW	*Flowgate Right Purchase per CRR Account Holder flowgate per CRR Auction*—The MW quantity that represents the total of CRR Account Holder *ccrh*'s FGR bids associated with FGR *f* awarded in CRR Auction *a*, for the hour.
crrh	none	A CRR Account Holder.
f	none	An FGR.
a	none	A CRR Auction.

7.5.6.3 Charge of PCRRs Pertaining to a CRR Auction

(1) For pre-assigned PTP Obligations allocated before each CRR Auction (annual or monthly auction), ERCOT shall charge each CRR Account Holder. The charge for each source and sink pair for a given Operating Hour is calculated as follows:

If OBLPR $_{(j, k), a}$ >0

$$\textbf{PCRROBLAMT}_{\ crrh,\, (j,\, k),\, a,\, tech} = \textbf{PCRROBLF}_{\ tech} \; \textbf{*} \; \textbf{OBLPR}_{\ (j,\, k),\, a}$$

$$* \textbf{PCRROBL}_{\textit{crrh, (j, k), a, tech}}$$

Otherwise

$$\textbf{PCRROBLAMT}_{\textit{crrh, (j, k), a, tech}} = \textbf{OBLPR}_{\textit{(j, k), a}} * \textbf{PCRROBL}_{\textit{crrh, (j, k), a, tech}}$$

The above variables are defined as follows:

Variable	Unit	Definition
$PCRROBLAMT_{crrh, (j, k), a, tech}$	$	*PCRR PTP Obligation Amount per CRR Account Holder per source and sink pair per CRR Auction by resource technology*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Obligations associated with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hour.
$PCRROBLF_{tech}$		*PCRR PTP Obligation pricing Factor per resource technology*—The pricing factor of pre-allocated PTP Obligations based on Resources of the technology *tech*. See Section 7.4.2, PCRR Allocation Terms and Conditions, item (f)(ii).
$OBLPR_{(j, k), a}$	$/MW per hour	*PTP Obligation Price per source and sink pair per CRR Auction*—The clearing price of a PTP Obligation with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
$PCRROBL_{crrh, (j, k), a, tech}$	MW	*PCRR PTP Obligation per CRR Account Holder per source and sink pair per CRR Auction by resource technology*—The MW quantity that represents the total of CRR Account Holder *ccrh*'s PTP Obligations associated with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hour.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
tech	none	A Resource technology. See Section 7.4.2, PCRR Allocation Terms and Conditions, item (f).

(2) For pre-assigned PTP Options allocated before each CRR Auction (annual or monthly auction), ERCOT shall charge each CRR Account Holder. The charge for each source and sink pair for a given Operating Hour is calculated as follows:

$$\textbf{PCRROPTAMT}_{\textit{crrh, (j, k), a, tech}} = \textbf{PCRROPTF}_{\textit{tech}} * \textbf{OPTPR}_{\textit{(j, k), a}} * \textbf{PCRROPT}_{\textit{crrh, (j, k), a, tech}}$$

The above variables are defined as follows:

Variable	Unit	Definition
$PCRROPTAMT_{crrh, (j, k), a, tech}$	$	*PCRR PTP Option Amount per CRR Account Holder per source and sink pair per CRR Auction by resource technology*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Options associated with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hour.
$PCRROPTF_{tech}$		*PCRR PTP Option pricing Factor per resource technology*—The pricing factor of pre-allocated PTP Options based on Resources of the technology *tech*. See Section 7.4.2, PCRR Allocation Terms and Conditions, item (f)

Variable	Unit	Definition
		(i).
$\text{OPTPR}_{(j,\,k),\,a}$	\$/MW per hour	*PTP Option Price per source and sink pair per CRR Auction*—The clearing price of a PTP Option with the source *j* and the sink *k* in CRR Auction *a*, for the hour.
$\text{PCRROPT}_{crrh,\,(j,\,k),\,a,\,tech}$	MW	*PCRR PTP Option per CRR Account Holder per source and sink pair per CRR Auction by resource technology*—The MW quantity that represents the total of CRR Account Holder *crrh*'s PTP Options with the source *j* and the sink *k* allocated before CRR Auction *a* based on Resources of the technology *tech*, for the hour.
crrh	none	A CRR Account Holder.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
tech	none	A Resource technology. See Section 7.4.2, PCRR Allocation Terms and Conditions, item (f).

7.5.6.4 CRR Auction Revenues

(1) The revenue for a given month produced from CRRs that source and sink within the same 2003 ERCOT CMZ, cleared in each CRR Auction, is calculated as follows:

$$\textbf{CRRZREV}_{z,\,a} = \sum_{h}\Big(\sum_{crrh}\sum_{j}\sum_{k}\textbf{OBLSAMT}_{crrh,(j,k),z,a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OPTSAMT}_{crrh,(j,k),z,a,h} + \sum_{crrh}\sum_{f}\textbf{FGRSAMT}_{crrh,f,z,a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OBLPAMT}_{crrh,(j,k),z,a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OPTPAMT}_{crrh,(j,k),z,a,h} + \sum_{crrh}\sum_{f}\textbf{FGRPAMT}_{crrh,f,z,a,h}\Big)$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{CRRZREV}_{z,\,a}$	\$	*CRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the CRRs that source and sink in CMZ *z*, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
$\text{OBLSAMT}_{crrh,\,(j,\,k),\,z,\,a,\,h}$	\$	*PTP Obligation Sale Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per hour*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
$\text{OPTSAMT}_{crrh,\,(j,\,k),\,z,\,a,\,h}$	\$	*PTP Option Sale Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per hour*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
$\text{FGRSAMT}_{crrh,\,f,\,z,\,a,\,h}$	\$	*Flowgate Right Sale Amount per CRR Account Holder per flowgate per zone per CRR Auction per hour*—The payment calculated for CRR Account Holder

Variable	Unit	Definition
		crrh of the MW quantity that represents the total FGR offers awarded in CRR Auction *a* associated with FGR *f* in CMZ *z*, for the hour *h*.
$\text{OBLPAMT}_{crrh, (j, k), z, a, h}$	$	*PTP Obligation Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
$\text{OPTPAMT}_{crrh, (j, k), z, a, h}$	$	*PTP Option Purchase Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids awarded in CRR Auction *a* with the source *j* and the sink *k*, both in CMZ *z*, for the hour *h*.
$\text{FGRPAMT}_{crrh, f, z, a, h}$	$	*Flowgate Right Purchase Amount per CRR Account Holder per flowgate per zone per CRR Auction per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total FGR offers awarded in CRR Auction *a* associated with FGR *f* in CMZ *z*, for the hour *h*.
a	none	A CRR Auction.
z	none	A 2003 ERCOT CMZ.
crrh	none	A CRR Account Holder that paid the invoice in full.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
f	none	An FGR.
h	none	An hour in the month.

(2) The revenue for a given month produced from CRRs that source and sink in different 2003 ERCOT CMZs, cleared in each CRR Auction, is calculated as follows:

$$\textbf{CRRNZREV}_{a} = \sum_{h}\Big(\sum_{crrh}\sum_{j}\sum_{k}\textbf{OBLSAMT}_{crrh,(j,k),a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OPTSAMT}_{crrh,(j,k),a,h} + \sum_{crrh}\sum_{f}\textbf{FGRSAMT}_{crrh,f,a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OBLPAMT}_{crrh,(j,k),a,h} + \sum_{crrh}\sum_{j}\sum_{k}\textbf{OPTPAMT}_{crrh,(j,k),a,h} + \sum_{crrh}\sum_{f}\textbf{FGRPAMT}_{crrh,f,a,h}\Big)$$

The above variables are defined as follows:

Variable	Unit	Definition
CRRNZREV_{a}	$	*CRR Non-Zonal Revenue*—The revenue resulted from the CRRs that source and sink in different CMZs, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
$\text{OBLSAMT}_{crrh, (j, k), a, h}$	$	*PTP Obligation Sale Amount per CRR Account Holder per source and sink pair per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
$\text{OPTSAMT}_{crrh, (j, k), a, h}$	$	*PTP Option Sale Amount per CRR Account Holder per source and sink pair per*

Variable	Unit	Definition
		CRR Auction—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
FGRSAMT $_{crrh,\ f,\ a,\ h}$	$	*Flowgate Right Sale Amount per CRR Account Holder per flowgate per CRR Auction*—The payment calculated for CRR Account Holder *crrh* of the MW quantity that represents the total FGR offers awarded in CRR Auction *a* associated with FGR *f* across CMZs, for the hour *h*.
OBLPAMT $_{crrh,\ (j,\ k),\ a,\ h}$	$	*PTP Obligation Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Obligation offers awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
OPTPAMT $_{crrh,\ (j,\ k),\ a,\ h}$	$	*PTP Option Purchase Amount per CRR Account Holder per source and sink pair per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total PTP Option bids awarded in CRR Auction *a* with the source *j* and the sink *k* in different CMZs, for the hour *h*.
FGRPAMT $_{crrh,\ f,\ a,\ h}$	$	*Flowgate Right Purchase Amount per CRR Account Holder per flowgate per CRR Auction*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents the total FGR offers awarded in CRR Auction *a* associated with FGR *f* across CMZs, for the hour *h*.
a	none	A CRR Auction.
crrh	none	A CRR Account Holder that paid the invoice in full.
(j, k)	none	A pair of source and sink Settlement Points in different CMZs.
f	none	An FGR across CMZs.
h	none	An hour in the month.

(3) The revenue for a given month produced from PCRRs that source and sink within the same 2003 ERCOT CMZ, pertaining to each CRR Auction, is calculated as follows:

$$\textbf{PCRRZREV}_{z,\,a} = \sum_{h} \Big(\sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \textbf{PCRROBLAMT}_{crrh,(j,k),z,a,tech,h} + \sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \textbf{PCRROPTAMT}_{crrh,(j,k),z,a,tech,h} \Big)$$

The above variables are defined as follows:

Variable	Unit	Definition
PCRRZREV $_{z,\ a}$	$	*PCRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the PCRRs that source and sink in CMZ *z*, pertaining to CRR Auction *a*, for the month.
PCRROBLAMT $_{crrh,\ (j,\ k),\ z,\ a,\ tech,\ h}$	$	*PCRR PTP Obligation Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Obligations pertaining to CRR Auction *a* with the source *j* and the sink *k* in CMZ *z*, based on Resources of the technology *tech*, for the hour *h*.
PCRROPTAMT $_{crrh,\ (j,\ k),\ z,\ a,\ tech,\ h}$	$	*PCRR PTP Option Amount per CRR Account Holder per source and sink pair per zone per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Options pertaining to CRR Auction *a* with the source *j* and the sink *k*

Variable	Unit	Definition
		in CMZ *z*, based on Resources of the technology *tech*, for the hour *h*.
a	none	A CRR Auction.
z	none	A 2003 ERCOT CMZ.
crrh	none	A CRR Account Holder that paid the invoice in full.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
tech	none	A Resource technology.
h	none	An hour in the month.

(4) The revenue for a given month produced from PCRRs that source and sink in different 2003 ERCOT CMZs, pertaining to each CRR Auction, is calculated as follows:

$$\textbf{PCRRNZREV}_{a} = \sum_{h} \Big(\sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \textbf{PCRROBLAMT}_{crrh,(j,k),a,tech,h} + \sum_{crrh} \sum_{j} \sum_{k} \sum_{tech} \textbf{PCRROPTAMT}_{crrh,(j,k),a,tech,h} \Big)$$

The above variables are defined as follows:

Variable	Unit	Definition
PCRRNZREV $_{a}$	$	*PCRR Non-Zonal Revenue per CRR Auction*—The revenue resulted from the PCRRs that source and sink in different CMZs, pertaining to CRR Auction *a*, for the month.
PCRROBLAMT $_{crrh,\ (j,\ k),\ a,\ tech,\ h}$	$	*PCRR PTP Obligation Amount per CRR Account Holder per source and sink pair per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Obligations pertaining to CRR Auction *a* with the source *j* and the sink *k* in different CMZs, based on Resources of the technology *tech*, for the hour *h*.
PCRROPTAMT $_{crrh,\ (j,\ k),\ a,\ tech,\ h}$	$	*PCRR PTP Option Amount per CRR Account Holder per source and sink pair per CRR Auction per resource technology per hour*—The charge calculated for CRR Account Holder *crrh* of the MW quantity that represents its total PTP Options pertaining to CRR Auction *a* with the source *j* and the sink *k* in different CMZs, based on Resources of the technology *tech*, for the hour *h*.
a	none	A CRR Auction.
crrh	none	A CRR Account Holder that paid the invoice in full.
(j, k)	none	A pair of source and sink Settlement Points in different CMZs.
tech	none	A Resource technology.
h	none	An hour in the month.

7.5.7 Method for Distributing CRR Auction Revenues

(1) ERCOT shall determine, for each month, the CRR Monthly Revenues (CMR). The CMR is the sum of:

(a) Monthly CRR revenue for that month; and

(b) PCRR revenues.

(2) For the first three years after the TNT Market Implementation Date, ERCOT shall credit the net CRR Auction revenue (including PCRR revenue) produced from CRRs cleared in each CRR Auction that source from a Settlement Point located within a 2003 ERCOT Congestion Management Zone (CMZ) and sink at a Settlement Point located within the same 2003 ERCOT CMZ to QSEs in the 2003 ERCOT CMZ on a zonal Load Ratio Share basis. All other net CRR Auction revenues must be allocated to QSEs on an ERCOT-wide Load Ratio Share basis. For these allocation purposes, any NOIE Load Zone is considered to be located entirely within the 2003 ERCOT CMZ that represented the largest Load for that NOIE or group of NOIEs in 2003. Before the end of the three-year period described above, the ERCOT Board shall consider whether to extend the policy or ratify some other alternative.

(3) For Initial distribution of CRR Monthly Revenues, revenues shall be paid to each QSE based on that QSE's Load Ratio Share in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

(4) ERCOT shall true up the distribution of CRR Monthly Revenues based on that QSE's Load Ratio Share in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

(5) The net CRR Auction Revenue produced from CRRs cleared and paid for in each CRR Auction that source from a Settlement Point within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ shall be distributed on a zonal Load Ratio Share basis. The portion of the net monthly CRR Auction Revenue to be distributed to each QSE with load in that zone for a given month is calculated as follows:

$$\mathbf{LACMRZAMT}_{z,\,q} = (-1) * \sum_{a} (\mathbf{CRRZREV}_{z,\,a} + \mathbf{PCRRZREV}_{z,\,a}) * \mathbf{MLRSZ}_{z,\,q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LACMRZAMT $_{z,\,q}$	$	*Load-Allocated CRR Monthly Revenue Zonal Amount per zone per QSE*—The payment to QSE *q* of the revenues resulted from the CRRs that source and sink in CMZ *z*, for the month.
CRRZREV $_{z,\,a}$	$	*CRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the CRRs that source and sink in CMZ *z*, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
PCRRZREV $_{z,\,a}$	$	*PCRR Zonal Revenue per zone per CRR Auction*—The revenue resulted from the PCRRs that source and sink in CMZ *z*, pertaining to CRR Auction *a*, for the month.
MLRSZ $_{q,\,z}$	none	*Monthly Load Ratio Share Zonal per QSE per zone*—The LRS of QSE *q* for its Load in CMZ *z*, for the peak-Load 15-minute Settlement Interval in the month.
q	none	A QSE.
z	none	A 2003 ERCOT CMZ.
a	none	A CRR Auction.

(6) The net CRR Auction Revenue produced from CRRs cleared and paid for in each CRR Auction that do not source from a Settlement Point within a 2003 ERCOT CMZ and sink at a Settlement Point located within the same 2003 ERCOT CMZ shall be distributed on an ERCOT-wide LRS basis. The portion of the net monthly CRR Auction Revenue Amount (from CRRs with paths that cross the 2003 ERCOT CMZ boundaries) to be distributed for a given month is calculated as follows:

$$\textbf{LACMRNZAMT}_{q} = \textbf{(-1) * } \sum_{a} \textbf{(CRRNZREV}_{a} \textbf{ + PCRRNZREV}_{a}\textbf{) * MLRS}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
LACMRNZAMT $_{q}$	$	*Load-Allocated CRR Monthly Revenue Non-Zonal Amount per QSE*—The payment to QSE *q* of the revenues resulted from the CRRs that source and sink in different CMZs, for the month.
CRRNZREV $_{a}$	$	*CRR Zonal Revenue per CRR Auction*—The revenue resulted from the CRRs that source and sink in different CMZs, cleared through CRR Auction Offers and CRR Auction Bids in CRR Auction *a*, for the month.
PCRRNZREV $_{a}$	$	*PCRR Zonal Revenue per CRR Auction*—The revenue resulted from the PCRRs that source and sink in different CMZs, pertaining to CRR Auction *a*, for the month.
MLRS $_{q}$	none	*Monthly Load Ratio Share per QSE*—The LRS calculated for QSE *q* for the peak-Load 15-minute Settlement Interval in the month. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
a	none	A CRR Auction.

7.6 CRR Balancing Account

(1) In the DAM, if the Congestion Rent is equal to or greater than the net amounts due to all CRR Owners for any Settlement Interval, then ERCOT shall pay the net amounts due to the CRR Owners and put any excess amount into the CRR Balancing Account.

(2) In the DAM, if the Congestion Rent is less than the net amounts due to all CRR Owners for any Settlement Interval, then ERCOT shall short-pay each CRR Owner on a prorated basis and shall keep track of how much each CRR Owner has been short-paid. The proration must be calculated using only the amounts due to the CRR Owner for CRRs settled in both the DAM and Real-Time and not using amounts due to ERCOT for PTP Obligations owned by the CRR Owner.

(3) ERCOT shall pay any positive balance in the CRR Balancing Account to each short-paid CRR Owner, with the amount paid to each CRR Owner being the lesser of (a) a prorated amount based on the short-paid amount for that CRR Owner compared to the total short-paid amount, and (b) the short-paid amount for that CRR Owner. Any remaining positive balance in the CRR Balancing Account must be allocated to all QSEs on the QSE's Load

Ratio Share in the interval coincident with the ERCOT-wide peak 15-minute Settlement Interval for the month.

7.7 Congestion Management in McCamey Area

7.7.1 Time Frame of Applicability for McCamey Area Flowgates

The procedures for determining McCamey Flowgate Rights (MCFRIs) and allocating them to wind-powered Generation Resources (WGRs) in the McCamey Area are applicable until 30 days after the ERCOT Board has approved ERCOT's certification that the sustainable export capability from the McCamey Area is greater than or equal to 900 MW. No more MCFRIs may be allocated 30 days following such action by the ERCOT Board.

7.7.2 Determination of McCamey Area and the McCamey Flowgate(s)

(1) MCFRIs are a type of FGR that must be allocated only to WGRs in the McCamey Area, which is an area of west Texas with an abundance of wind-powered generation for which there are export capability limitations. ERCOT shall determine the boundaries of the McCamey Area and publish maps on the MIS Secure Area indicating the Electrical Buses contained in the McCamey Area.

(2) ERCOT shall post to the MIS Secure Area the specific predefined directional network element that defines each McCamey Area flowgate. The elements that comprise new McCamey Area flowgates may be established due to changes in the transmission system.

(3) ERCOT shall identify WGRs eligible for MCFRI allocation in the McCamey Area that:

(a) Have demonstrated that the WGR is in commercial operation or is expected to be in commercial operation during the period for which MCFRIs will be allocated. This determination is made at ERCOT's sole discretion;

(b) Have significant impact on the most limiting local operational constraint; and

(c) Cannot operate their facilities at full capacity simultaneously with other WGRs in the McCamey Area, when all local transmission lines are in service, without violating ERCOT reliability criteria.

(4) ERCOT shall post on the MIS Public Area a current geographical map and an electrical one-line diagram of the boundaries of the McCamey Area. ERCOT shall revise the map and diagram as necessary to reflect any changes in transmission system configuration or new interconnections of WGRs in west Texas.

(5) WGRs shall designate a Congestion Revenue Right (CRR) Account Holder(s) to receive allocated MCFRIs.

7.7.3 Allocation of McCamey Flowgate Rights (MCFRIs)

(1) ERCOT shall determine the "Capacity Impact" of each McCamey Area WGR eligible for MCFRIs on each McCamey Area flowgate by multiplying the maximum rated output for the WGR times its Shift Factor from the base case transmission model for the corresponding McCamey Area flowgate relative to the Load-weighted average Shift Factor of all Electrical Buses in ERCOT.

(2) Prior to each CRR Auction, ERCOT shall allocate 90% of the limit for each McCamey Area flowgate adjusted for impact of allocated PCRRs for the corresponding auction as MCFRIs to each McCamey Area WGR in proportion to its Capacity Impact as a percentage of the sum of all Capacity Impacts for McCamey Area WGRs for the corresponding flowgate. All commercial and committed WGRs in the McCamey Area must be included in the analysis, but MCFRIs may be allocated only to WGRs that are in commercial operation. The determination of available McCamey Area flowgate capacity must account for reduced flowgate element capacities resulting from CRRs already sold or allocated.

(3) ERCOT shall allocate 90% of McCamey Area flowgate capacity to be auctioned in any particular auction and the DAM, adjusted for PCRR impacts and MCFRIs previously allocated, as MCFRIs to each McCamey Area WGR as described in (2) above 25 days prior to an annual auction, ten Business Days prior to a monthly auction, and by no later than one hour prior to the DAM.

7.7.3.1 Accommodation of New or Recommissioned WGRs

(1) In the case of a new or re-commissioned WGR located in the McCamey Area, ERCOT must determine in its sole discretion that the WGR is anticipated to be in commercial operation in order for the new capacity to be included in the analysis described in Section 7.7.3, Allocation of McCamey Flowgate Rights (MCFRIs).

(2) MCFRIs must be reserved for each new or recommissioned WGR for each whole month during which it is anticipated, in ERCOT's sole discretion, to be in commercial operation or in pre-startup testing. MCFRIs reserved for a new or recommissioned WGR may only be allocated for that WGR if it is anticipated, in ERCOT's sole discretion, to be in commercial operation or in pre-startup testing at the beginning of the month for which the MCFRIs are effective. Any MCFRIs reserved for a month but not allocated for a new or recommissioned WGR will be allocated:

(a) For WGRs that are in commercial operation in the same proportion as their other MCFRIs are allocated; and,

(b) For WGRs in startup and testing as described in Section 7.7.3.2, New or Recommissioned Unit Startup and Testing.

7.7.3.2 New or Recommissioned Unit Startup and Testing

For each new or recommissioned WGR in the McCamey Area, the WGR owner shall supply ERCOT with a test plan. The plan shall indicate how the WGR will increase capacity, along with the expected dates that the capacity will be available. During the testing period before commercial operation, ERCOT shall allocate MCFRIs for the new or recommissioned WGR equal to the test plan capacity impact (test plan capacity times its impact on the corresponding McCamey Area Flowgate) if it is less than five MW. If the test plan capacity impact is equal to or greater than 5MW, ERCOT shall allocate MCFRIs for the new or recommissioned WGR proportional to the test plan capacity impact's proportion of total available McCamey Area WGR capacity impact.

7.7.3.3 New or Recommissioned Unit Commercial Operation

The owner of a WGR coming On-Line in the McCamey Area shall notify ERCOT three Business Days before expected commercial operation. The notice must include the MW of generation capacity expected to become commercial based on the PUCT certification of the Generation Resource as a REC generator, the date of expected commercial operation, and the QSE(s) representing the WGR with the associated capacity that the WGR will be able to provide. The owner of the WGR shall notify ERCOT of any delays in the expected commercial operation.

7.8 Bilateral Trades and ERCOT CRR Registration System

(1) Market Participants may sell or trade PTP Options, PTP Obligations and FGRs bilaterally, except PTP Options with Refund and PTP Obligations with Refund.

(2) The characteristics of the CRRs sold or traded bilaterally, including CRR source and CRR sink and time-of-use block, may not be modified from the terms of the original CRR.

(3) ERCOT shall initially populate a database of CRR Owners with the annual and monthly first-buyers of CRRs and first-recipients of PCRRs and MCFRIs.

(4) A transfer of CRRs through the ERCOT CRR registration system is not effective until the selling CRR Account Holder reports the transaction, the buying CRR Account Holder acknowledges the transaction, and both parties meet ERCOT's credit requirements to support the transfer. Until all of those occur, the selling CRR Account Holder is considered the CRR Owner for purposes of these Protocols, including financial responsibility.

(5) For CRR ownership to be effective in the DAM, the CRR must be registered through the ERCOT CRR registration system prior to the Day-Ahead Market. PTP Obligations acquired in DAM may not change ownership in the ERCOT CRR registration system after DAM execution.

7.9 CRR Settlements

7.9.1 Day-Ahead CRR Payments and Charges

7.9.1.1 Payments and Charges for PTP Obligations Settled in DAM

(1) Except as specified otherwise in paragraph (2) below, ERCOT shall pay or charge the owner of each Point-to-Point (PTP) Obligation based on the difference in the Day-Ahead Settlement Point Price between the sink Settlement Point and the source Settlement Point.

(2) For PTP Obligations that have a positive value and source or sink at a Resource Node, the PTP Obligation payment may be reduced due to directional network elements that are oversold in previous Congestion Revenue Right (CRR) auctions.

(3) The payment or charge to each CRR Owner for a given Operating Hour of PTP Obligations with each pair of source and sink Settlement Points settled in the Day-Ahead Market (DAM) is calculated as follows:

If the PTP Obligation has a non-positive value or both source and sink at a Load Zone or Hub, i.e., ($\text{DAOBLPR}_{(j, k)} \leq 0$) OR ($j$ is a Load Zone or Hub and k is also a Load Zone or Hub), then

$$\textbf{DAOBLAMT}_{o, (j, k)} = \textbf{(-1) * DAOBLTP}_{o, (j, k)}$$

If the PTP Obligation has a positive value and either source or sink is a Resource Node, then

$$\textbf{DAOBLAMT}_{o, (j, k)} = \textbf{(-1) * Max ((DAOBLTP}_{o, (j, k)} \textbf{– DAOBLDA}_{o, (j, k)}\textbf{), Min (DAOBLTP}_{o, (j, k)}\textbf{, DAOBLHV}_{o, (j, k)}\textbf{))}$$

Where:

The target payment:

$$\text{DAOBLTP}_{o, (j, k)} = \text{DAOBLPR}_{(j, k)} * \text{DAOBL}_{o, (j, k)}$$

The price based on the difference of the Settlement Point Prices:

$$\text{DAOBLPR}_{(j, k)} = \text{DASPP}_{k} - \text{DASPP}_{j}$$

The derated amount:

$$\text{DAOBLDA}_{o, (j, k)} = \text{OBLDRPR}_{(j, k)} * \text{DAOBL}_{o, (j, k)}$$

The price used to calculate the derated amount:

$$\text{OBLDRPR}_{(j, k)} = \sum_{c} (\text{Max}(0, \text{DAWASF}_{j, c} – \text{DAWASF}_{k, c}) * \text{DASP}_{c} * \text{DRF}_{c})$$

The hedge value:

$$\text{DAOBLHV}_{o, (j, k)} = \text{DAOBLHVPR}_{(j, k)} * \text{DAOBL}_{o, (j, k)}$$

The price of the hedge value:

If the source, j, is a Load Zone or Hub and the sink, k, is a Resource Node,

$$DAOBLHVPR_{(j,\,k)} = Max\ (0, MAXRESPR_{k} - DASPP_{j})$$

If the source, j, is a Resource Node and the sink, *k*, is a Load Zone or Hub,

$$DAOBLHVPR_{(j,\,k)} = Max\ (0, DASPP_{k} - MINRESPR_{j})$$

If the source, j, is a Resource Node and the sink, k, is also a Resource Node,

$$DAOBLHVPR_{(j,\,k)} = Max\ (0, MAXRESPR_{k} - MINRESPR_{j})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$DAOBLAMT_{o, (j, k)}$	$	*Day-Ahead Obligation Amount per CRR Owner per source and sink pair*—The payment or charge to CRR Owner *o* for the PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOBLTP_{o, (j, k)}$	$	*Day-Ahead Obligation Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOBLHV_{o, (j, k)}$	$	*Day-Ahead Obligation Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOBLDA_{o, (j, k)}$	$	*Day-Ahead Obligation Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOBLPR_{(j, k)}$	$/MW per hour	*Day-Ahead Obligation Price per source and sink pair*—The DAM price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
$DASPP_{j}$	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j*, for the hour.
$DASPP_{k}$	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k*, for the hour.
$OBLDRPR_{(j, k)}$	$/MW per hour	*Obligation Deration Price per source and sink pair*—The deration price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
$DASP_{c}$	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF_{c}	none	*Deration Factor per constraint*—The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
$DAWASF_{j, c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the directional network element for constraint *c*, in the hour.
$DAWASF_{k, c}$	None	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the directional network element for constraint *c*, in the hour.
$DAOBLHVPR_{(j, k)}$	$/MWh	*Day-Ahead Obligation Hedge Value Price per source and sink pair*—The Day-Ahead hedge price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
$MINRESPR_{j}$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for the

Variable	Unit	Definition
		Resources located at the source Settlement Point *j*.
$MAXRESPR_{k}$	\$/MWh	*Max Resource Price for sink*—The highest Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
$DAOBL_{o, (j, k)}$	MW	*Day-Ahead Obligation per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A constraint associated with a directional network element for the hour.

(4) The net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations settled in the DAM is calculated as follows:

$$\mathbf{DAOBLAMTOTOT}_{o} = \mathbf{DAOBLCROTOT}_{o} + \mathbf{DAOBLCHOTOT}_{o}$$

Where:

$$DAOBLCROTOT_{o} = \sum_{j} \sum_{k} \text{Min}\,(0, DAOBLAMT_{o, (j, k)})$$

$$DAOBLCHOTOT_{o} = \sum_{j} \sum_{k} \text{Max}\,(0, DAOBLAMT_{o, (j, k)})$$

The above variables are defined as follows:

Variable	Unit	Definition
$DAOBLAMTOTOT_{o}$	\$	*Day-Ahead Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* for all its PTP Obligations settled in the DAM, for the hour.
$DAOBLCROTOT_{o}$	\$	*Day-Ahead Obligation Credit Owner Total per CRR Owner*—The total payment to CRR Owner *o* for its PTP Obligations settled in the DAM, for the hour.
$DAOBLCHOTOT_{o}$	\$	*Day-Ahead Obligation Charge Owner Total per CRR Owner*—The total charge to CRR Owner *o* for its PTP Obligations settled in the DAM, for the hour.
$DAOBLAMT_{o, (j, k)}$	\$	*Day-Ahead Obligation Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for its PTP Obligations with the source *j* and the sink *k* settled in the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.1.2 Payments for PTP Options Settled in DAM

(1) Except as specified otherwise in paragraph (2) below, ERCOT shall pay the owner of a PTP Option the difference in the Day-Ahead Settlement Point Price between the sink Settlement Point and the source Settlement Point, if positive.

(2) For PTP Options that source or sink at a Resource Node, the PTP Option payment may be reduced due to transmission elements that are oversold in previous CRR auctions.

(3) The payment to each CRR Owner for a given Operating Hour of PTP Options with each pair of source and sink Settlement Points settled in the DAM is calculated as follows:

If the source, *j*, is a Load Zone or Hub and sink, *k*, is also a Load Zone or Hub, then

$$\mathbf{DAOPTAMT}_{o,\,(j,\,k)} = \mathbf{(-1) * DAOPTTP}_{o,\,(j,\,k)}$$

If either the source, *j*, or sink, *k*, is a Resource Node, then

$$\mathbf{DAOPTAMT}_{o,\,(j,\,k)} = \mathbf{(-1) * Max\ ((DAOPTTP}_{o,\,(j,\,k)} \mathbf{- DAOPTDA}_{o,\,(j,\,k)}\mathbf{),\ Min\ (DAOPTTP}_{o,\,(j,\,k)}\mathbf{,\ DAOPTHV}_{o,\,(j,\,k)}\mathbf{))}$$

Where:

The target payment:

$$\text{DAOPTTP}_{o,\,(j,\,k)} = \text{DAOPTPR}_{(j,\,k)} * \text{DAOPT}_{o,\,(j,\,k)}$$

The price based on the difference of the Settlement Point Prices:

$$\text{DAOPTPR}_{o,\,(j,\,k)} = \text{Max}\ (0, \text{DASPP}_{k} - \text{DASPP}_{j})$$

The derated amount:

$$\text{DAOPTDA}_{o,\,(j,\,k)} = \text{OPTDRPR}_{(j,\,k)} * \text{DAOPT}_{o,\,(j,\,k)}$$

The price used to calculate the derated amount:

$$\text{OPTDRPR}_{(j,\,k)} = \sum_{c} (\text{Max}\ (0, \text{DAWASF}_{j,\,c} - \text{DAWASF}_{k,\,c}) * \text{DASP}_{c} * \text{DRF}_{c})$$

The hedge value:

$$\text{DAOPTHV}_{o,\,(j,\,k)} = \text{DAOPTHVPR}_{(j,\,k)} * \text{DAOPT}_{o,\,(j,\,k)}$$

The price of the hedge value:

If the source, *j*, is a Load Zone or Hub and the sink, *k*, is a Resource Node,

$$\text{DAOPTHVPR}_{(j,\,k)} = \text{Max}\ (0, \text{MAXRESPR}_{k} - \text{DASPP}_{j})$$

If the source, *j*, is a Resource Node and the sink, *k*, is a Load Zone or Hub,

$$\text{DAOPTHVPR}_{(j,\,k)} = \text{Max}\ (0, \text{DASPP}_{k} - \text{MINRESPR}_{j})$$

If the source, *j*, is a Resource Node and the sink, *k*, is also a Resource Node,

$$\text{DAOPTHVPR}_{(j,\,k)} = \text{Max}\ (0, \text{MAXRESPR}_{k} - \text{MINRESPR}_{j})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DAOPTAMT}_{o,\,(j,\,k)}$	$	*Day-Ahead Option Amount per CRR Owner per source and sink pair* —The payment to CRR Owner *o* for the PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.

Variable	Unit	Definition
$DAOPTTP_{o, (j, k)}$	$	*Day-Ahead Option Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOPTHV_{o, (j, k)}$	$	*Day-Ahead Option Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOPTDA_{o, (j, k)}$	$	*Day-Ahead Option Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
$DAOPTPR_{(j, k)}$	$/MW per hour	*Day-Ahead Option Price per source and sink pair* —The DAM price of a PTP Option with the source *j* and the sink *k*, for the hour.
$DASPP_{j}$	$/MWh	*Day-Ahead Settlement Point Price at source* —The DAM SPP at the source Settlement Point *j*, for the hour.
$DASPP_{k}$	$/MWh	*Day-Ahead Settlement Point Price at sink* —The DAM SPP at the sink Settlement Point *k*, for the hour.
$OPTDRPR_{(j, k)}$	$/MW per hour	*Option Deration Price per source and sink pair*—The deration price of a PTP Option with the source *j* and the sink *k*, for the hour.
$DASP_{c}$	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF_{c}	none	*Deration Factor per constraint*— The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
$DAWASF_{j, c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the directional network element for constraint *c*, in the hour.
$DAWASF_{k, c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the directional network element for constraint *c*, in the hour.
$DAOPTHVPR_{(j, k)}$	$/MWh	*Day-Ahead Option Hedge Value Price per source and sink pair*—The Day-Ahead hedge price of a PTP Option with the source *j* and the sink *k*, for the hour.
$MINRESPR_{j}$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for Resources located at the source Settlement Point *j*.
$MAXRESPR_{k}$	$/MWh	*Max Resource Price for sink*—The highest Maximum Resource Price for Resources located at the sink Settlement Point *k*.
$DAOPT_{o, (j, k)}$	MW	*Day-Ahead Option per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A constraint associated with a directional network element for the hour.

(4) The total payment to each CRR Owner for the Operating Hour of all its PTP Options settled in the DAM is calculated as follows:

$$\mathbf{DAOPTAMTOTOT}_{\,o} \quad = \quad \sum_{j} \sum_{k} \mathbf{DAOPTAMT}_{\,o,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAOPTAMTOTOT $_{o}$	$	*Day-Ahead Option Amount Owner Total per CRR Owner*—The total payment to CRR Owner *o* for all its PTP Options settled in the DAM, for the hour.
DAOPTAMT $_{o, (j, k)}$	$	*Day-Ahead Option Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for its PTP Options with the source *j* and the sink *k* settled in the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(5) For informational purposes, the following calculation of PTP Option value shall be posted on the Market Information System (MIS) Public Area:

$$\textbf{DAOPTPRINFO}_{(j,\,k)} = \sum_{c} \textbf{(DASP}_{c}\textbf{ * Max (0, (DAWASF}_{j,\,c}\textbf{ – DAWASF}_{k,\,c}\textbf{)))}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAOPTPRINFO $_{(j, k)}$	$/MW per hour	*Day-Ahead Option Informational Price per pair of source and sink*—The Informational DAM price of the PTP Options with the source Settlement Point *j* and the sink Settlement Point *k*, for the hour.
DAWASF $_{j, c}$		*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and for the constrained directional network element for constraint *c*, in the hour.
DAWASF $_{k, c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and for the constrained directional network element for constraint *c*, in the hour.
DASP $_{c}$	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price for the constraint *c* for the hour.
c	none	A constraint associated with a directional network element for the hour.

7.9.1.3 Minimum and Maximum Resource Prices

(1) The following prices specified in paragraphs (2) and (3) below are used in CRR hedge value calculation for CRRs settled in the DAM and PTP Options settled in Real-Time.

(2) Minimum Resource Prices of source Settlement Points are:

$$\textbf{MINRESPR}_{j} = \textbf{Min (MINRESRPR}_{j,\,r}\textbf{)}_{r}$$

Where:

Minimum Resource Prices for Resources located at source Settlement Points (**MINRESRPR** $_{j,\,r}$) are:

(a) Nuclear = -$20.00/MWh;

(b) Hydro = -$20.00/MWh;

(c) Coal and Lignite = $0.00/MWh;

(d) Combined Cycle greater than 90 MW = FIP * 5 MMBtu/MWh;

(e) Combined Cycle less than or equal to 90 MW = FIP * 6 MMBtu/MWh;

(f) Gas -Steam Supercritical Boiler = FIP * 6.5 MMBtu/MWh;

(g) Gas Steam Reheat Boiler = FIP * 7.5 MMBtu/MWh;

(h) Gas Steam Non-reheat or boiler without air-preheater = FIP * 10.5 MMBtu/MWh;

(i) Simple Cycle greater than 90 MW = FIP * 10 MMBtu/MWh;

(j) Simple Cycle less than or equal to 90 MW = FIP * 11 MMBtu/MWh;

(k) Diesel = FIP * 12 MMBtu/MWh;

(l) Wind = -$35/MWh;

(m) Reliability Must-Run (RMR) Resource = RMR contract price Energy Offer Curve at Low Sustained Limit (LSL); and

(n) Other Renewable = -$10.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
MINRESPR $_j$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for the Resources located at the source Settlement Point *j*.
MINRESRPR $_j$	$/MWh	*Minimum Resource Price for Resource*—The Minimum Resource Price for the Resources located at the source Settlement Point *j*.
r	none	A Generation Resource located at the source Settlement Point j.
j	none	A source Settlement Point.

(3) Maximum Resource Prices of sink Settlement Points are:

$$\textbf{MAXRESPR}_{k} = \textbf{Max (MAXRESRPR}_{k,\,r}\textbf{)}_{r}$$

Where:

Maximum Resource Prices for Resources located at sink Settlement Points **(MAXRESRPR $_{k, r}$)** are:

(a) Nuclear = $15.00/MWh;

(b) Hydro = $10.00/MWh;

(c) Coal and Lignite = $18.00/MWh;

(d) Combined Cycle greater than 90 MW = FIP * 9 MMBtu/MWh;

(e) Combined Cycle less than or equal to 90 MW = FIP * 10 MMBtu/MWh;

(f) Gas -Steam Supercritical Boiler = FIP * 10.5 MMBtu/MWh;

(g) Gas Steam Reheat Boiler = FIP * 11.5 MMBtu/MWh;

(h) Gas Steam Non-reheat or boiler without air-preheater = FIP * 14.5 MMBtu/MWh;

(i) Simple Cycle greater than 90 MW = FIP * 14 MMBtu/MWh;

(j) Simple Cycle less than or equal to 90 MW = FIP * 15 MMBtu/MWh;

(k) Diesel = FIP * 16 MMBtu/MWh;

(l) Wind = $0/MWh;

(m) RMR Resource = RMR contract price Energy Offer Curve at HSL; and

(n) Other Renewable = $0.

The above variables are defined as follows:

Variable	**Unit**	**Definition**
MAXRESPR $_k$	$/MWh	*Maximum Resource Price for source*—The highest Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
MAXRESRPR $_k$	$/MWh	*Maximum Resource Price for Resource*—The Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
r	none	A Generation Resource located at the sink Settlement Point k.
k	none	A sink Settlement Point.

7.9.1.4 Payments for FGRs Settled in DAM

(1) If a Flowgate Right (FGR) is competitive, i.e., all directional network elements associated with the FGR are Competitive Constraints, ERCOT shall pay the owner of the FGR an

amount equal to the sum of the Shadow Price of the hour for each directional network element associated with the FGR for each contingency (including the null contingency or base case) normalized to the impact of the principal network element of the FGR (the normal rating of which is used to determine the total MW amount for the flowgate). The payment to each CRR Owner for its FGRs determined by the principle network element of each flowgate for a given hour is calculated as follows:

$$\textbf{DAFGRAMT}_{o,f} = \textbf{(-1)} * \textbf{DAFGRTP}_{o,f}$$

Where:

$$\text{DAFGRTP}_{o,f} = \text{DAFGRPR}_{f} * \text{DAFGR}_{o,f}$$

$$\text{DAFGRPR}_{f} = \sum_{e \in f} (\text{INF}_{f,e} * \sum_{c} \text{DASP}_{e,c})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DAFGRAMT}_{o,f}$	$	*Day-Ahead FGR Amount per CRR Owner per flowgate*—The payment to CRR Owner *o* of the flowgate *f* settled in DAM, for the hour.
$\text{DAFGRTP}_{o,f}$	$	*Day-Ahead FGR Target Payment per CRR Owner per flowgate*—The target payment for CRR Owner *o*'s flowgate *f* settled in the DAM, for the hour.
DAFGRPR_{f}	$/MW per hour	*Day-Ahead FGR Price per flowgate*—The DAM price of the flowgate *f* for the hour.
$\text{DASP}_{e,c}$	$/MW per hour	*Day-Ahead Shadow Price per element per constraint*—The DAM Shadow Price on the directional network element *e*, for constraint *c*, for the hour.
$\text{INF}_{f,e}$	none	*Impact Normalization Factor per element per flowgate*—The parameter that reflects the normalized impact on the directional network element *e* relative to the impact on the principal network element of flowgate *f*.
$\text{DAFGR}_{o,f}$	MW	*Day-Ahead FGR per CRR Owner per flowgate*—The CRR Owner *o*'s total number of FGRs determined by the principle element of flowgate *f* settled in the DAM for the hour.
o	none	A CRR Owner.
f	none	A flowgate.
e	none	A directional network element.
c	none	A constraint.
$e \in f$	none	The directional network element *e* belongs to the flowgate *f*.

(2) If an FGR is non-competitive, i.e., one or more directional network elements associated with the FGR are Non-Competitive Constraints, the FGR payment may be reduced due to transmission elements that are oversold in previous CRR auctions. The payment for McCamey Flowgate Right (MCFRI), when it is not designated as a Competitive Constraint, is calculated in paragraph (3); the payment for any other FGR, when it is non-competitive, will be specified upon introduction of the FGR.

(3) The payment to each CRR Owner for its MCFRI for a given hour, when MCFRI is not designated as a Competitive Constraint, is calculated as follows:

$$\mathbf{DAFGRAMT}_{o,\,MCFRI} = \mathbf{(-1) * Max\,((DAFGRTP}_{o,\,MCFRI}\mathbf{ - DAFGRDA}_{o,\,MCFRI}\mathbf{),\ Min\,(DAFGRTP}_{o,\,MCFRI}\mathbf{,\ DAFGRHV}_{o,\,MCFRI}\mathbf{))}$$

Where:

The target payment:

$$\text{DAFGRTP}_{o,\,MCFRI} = \text{DAFGRPR}_{MCFRI} * \text{DAFGR}_{o,\,MCFRI}$$

$$\text{DAFGRPR}_{MCFRI} = \sum_{e \in MCFRI} (\text{INF}_{MCFRI,\,e} * \sum_{c} \text{DASP}_{e,\,c})$$

The derated amount:

$$\text{DAFGRDA}_{o,\,MCFRI} = \text{FGRDRPR}_{MCFRI} * \text{DAFGR}_{o,\,MCFRI}$$

$$\text{FGRDRPR}_{MCFRI} = \sum_{e \in MCFRI} (\text{INF}_{MCFRI,\,e} * \sum_{c} (\text{DASP}_{e,\,c} * \text{DRF}_{e,\,c}))$$

The hedge value:

$$\text{DAFGRHV}_{o,\,MCFRI} = \text{DAFGRHVPR}_{MCFRI} * \text{DAFGR}_{o,\,MCFRI}$$

$$\text{DAFGRHVPR}_{MCFRI} = \text{Max}\,(0,\ (\text{DAWALBEP} - \text{MINRESPR}_{j,\,MCFRI} - \sum_{e \notin MCFRI} \sum_{c} (\text{DASP}_{e,\,c} * (\text{DASFMCWGRS}_{e,\,c} - \text{DAWASFLB}_{e,\,c}))) / (\text{DASFMCWGRS}_{e=MCFRI\ principle\ element,\ c(Base\ Case} - \text{DAWASFLB}_{e=MCFRI\ principle\ element,\ c \in Base\ Case}))$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DAFGRAMT}_{o,\,f}$	$	*Day-Ahead FGR Amount per CRR Owner per flowgate*—The payment to CRR Owner *o* of the FGRs associated with flowgate *f* settled in DAM, for the hour.
$\text{DAFGRTP}_{o,\,f}$	$	*Day-Ahead FGR Target Payment per CRR Owner per flowgate*—The target payment for CRR Owner *o*'s flowgate *f* settled in the DAM, for the hour.
$\text{DAFGRHV}_{o,\,f}$	$	*Day-Ahead FGR Hedge Value per CRR Owner per flowgate*—The hedge value of CRR Owner *o*'s flowgate *f* settled in the DAM, for the hour.
$\text{DAFGRDA}_{o,\,f}$	$	*Day-Ahead FGR Derated Amount per CRR Owner per flowgate*—The derated amount of CRR Owner *o*'s flowgate *f* settled in the DAM, for the hour.
DAFGRPR_{f}	$/MW per hour	*Day-Ahead FGR Price per flowgate*—The DAM price of the flowgate *f* for the hour.
FGRDRPR_{f}	$/MW per hour	*FGR Deration Price per flowgate*—The deration price of the flowgate *f* for the hour.

INF $_{f, e}$	none	*Impact Normalization Factor per element per flowgate*—The parameter that reflects the normalized impact on the directional network element *e* relative to the impact on the principal network element of flowgate *f*.
DASP $_{e, c}$	\$/MW per hour	*Day-Ahead Shadow Price per element per constraint*—The DAM Shadow Price on the directional network element *e*, for constraint *c*, for the hour.
DAFGR $_{o, f}$	MW	*Day-Ahead FGR per CRR Owner per flowgate*—The CRR Owner *o*'s total number of FGRs determined by the principle element of the flowgate *f* settled in the DAM for the hour.
DRF $_{e, c}$	none	*Deration Factor per element per constraint*— The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
DAWASFLB $_{e, c}$	none	*Day-Ahead Weighted Average Shift Factor of Load Buses per element per constraint*—The Day-Ahead weighted average Shift Factor for all Load buses on the directional network element *e*, for constraint *c*, in the hour.
DASFMCWGRS $_{e, c}$	none	*Day-Ahead Shift Factor of McCamey WGRs per element per constraint*—The Day-Ahead McCamey area Wind Generation Resource (WGR) maximum rated output weighted Shift Factor on the directional network element *e*, for constraint *c*, in the hour.
DAFGRHVPR $_{f}$	\$/MWh	*Day-Ahead FGR Hedge Value Price per flowgate*—The Day-Ahead hedge price of the flowgate *f*, for the hour.
MINRESPR $_{j, MCFRI}$	\$/MWh	*Minimum Resource Price*—The lowest Minimum Resource Price for the Resources located at the source *j* of MCFRI.
DAWALBEP	\$/MWh	*Day-Ahead Weighted Average Load Bus Energy Price*—The weighted average DAM energy price of all Load buses for the hour.
o	none	A CRR Owner.
f	none	A flowgate; in this application *f* = MCFRI.
e	none	A directional network element, including principal element.
c	none	A constraint.
j	none	A source Settlement Point
$e \in$ MCFRI	none	The directional network element *e* belongs to MCFRI.
$e \notin$ MCFRI	none	The directional network element *e* doesn't belong to MCFRI.
$c \in$ Base Case	none	The constraint *c* is under the Base Case.

(4) The total of the payments to each CRR Owner for the Operating Hour of all its FGRs settled in the DAM is calculated as follows:

$$\textbf{DAFGRAMTOTOT}_{\ o} = \sum_{f} \textbf{DAFGRAMT}_{\ o,\ f}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAFGRAMTOTOT $_{o}$	\$	*Day-Ahead FGR Amount Owner Total per CRR Owner*—The total payment to CRR Owner *o* of all its FGRs settled in the DAM, for the hour.
DAFGRAMT $_{o, f}$	\$	*Day-Ahead FGR Amount per CRR Owner per flowgate*—The payment to CRR Owner *o* of the FGRs associated with flowgate *f* settled in DAM, for the hour.
o	none	A CRR Owner.

f	none	A flowgate.

7.9.1.5 Payments and Charges for PTP Obligations with Refund Settled in DAM

(1) Except as specified otherwise in paragraph (2) below, ERCOT shall pay the owner of a PTP Obligation with Refund the difference in the Day-Ahead Settlement Point Prices between the sink Settlement Point and the source Settlement Point, subject to a charge for refund, when the price difference is positive, as described in the item (e) (i) of Section 7.4.2, PCRR Allocation Terms and Conditions.

(2) The payment of PTP Obligations with Refund may be further reduced due to transmission elements that are oversold in previous CRR auctions.

(3) The payment or charge to each CRR Owner for a given Operating Hour of PTP Obligations with Refund with each pair of source and sink Settlement Points settled in the DAM is calculated as follows:

If the PTP Obligation with Refund has a non-positive value, i.e., ($\text{DAOBLPR}_{(j,\,k)} \le 0$), then

$$\textbf{DAOBLRAMT}_{o,\,(j,\,k)} = \textbf{(-1) * DAOBLRTP}_{o,\,(j,\,k)}$$

If the PTP Obligation with Refund has a positive value, i.e., ($\text{DAOBLPR}_{(j,\,k)} > 0$), then

$$\textbf{DAOBLRAMT}_{o,\,(j,\,k)} = \textbf{(-1) * Max (DAOBLRTP}_{o,\,(j,\,k)}\textbf{ - DAOBLRDA, Min (DAOBLRTP, DAOBLRHV))}$$

Where:

The target payment:

$$\text{DAOBLRTP}_{o,\,(j,\,k)} = \text{DAOBLPR}_{(j,\,k)} * \text{Min}(\text{DAOBLR}_{o,\,(j,\,k)}, \text{OBLRACT}_{o,\,(j,\,k)})$$

$$\text{DAOBLPR}_{(j,\,k)} = \text{DASPP}_k - \text{DASPP}_j$$

$$\text{OBLRACT}_{o,\,(j,\,k)} = \sum_y (\sum_r (\text{OBLROF}_{o,\,r,\,(j,\,k)} * \text{RESACT}_{r,\,(j,\,k),\,y}) * \text{TLMP}_y) / (\sum_y \text{TLMP}_y) * \text{OBLRF}_{o,\,(j,\,k)}$$

If ($\text{OS}_{r,\,y}$ exists)

$\text{RESACT}_{r,\,(j,\,k),\,y} = \text{OS}_{r,\,y}$

Otherwise

If ($\text{EBP}_{r,\,y}$ exists)

$\text{RESACT}_{r,\,(j,\,k),\,y} = \text{EBP}_{r,\,y}$

Otherwise

$\text{RESACT}_{r,\,(j,\,k),\,y} = \text{BP}_{r,\,y}$

The derated amount:

$$\text{DAOBLRDA}_{o,(j,k)} = \text{OBLDRPR}_{(j,k)} * \text{Min}(\text{DAOBLR}_{o,(j,k)}, \text{OBLRACT}_{o,(j,k)})$$

$$\text{OBLDRPR}_{(j,k)} = \sum_{c} (\text{Max}(0, \text{DAWASF}_{j,c} - \text{DAWASF}_{k,c}) * \text{DASP}_{c} * \text{DRF}_{c})$$

The hedge value:

$$\text{DAOBLRHV}_{o,(j,k)} = \text{DAOBLHVPR}_{(j,k)} * \text{Min}(\text{DAOBLR}_{o,(j,k)}, \text{OBLRACT}_{o,(j,k)})$$

If the source, j, is a Load Zone or Hub and the sink, k, is a Resource Node,

$$\text{DAOBLHVPR}_{(j,k)} = \text{Max}(0, \text{MAXRESPR}_{k} - \text{DASPP}_{j})$$

If the source, j, is a Resource Node and the sink, k, is a Load Zone or Hub,

$$\text{DAOBLHVPR}_{(j,k)} = \text{Max}(0, \text{DASPP}_{k} - \text{MINRESPR}_{j})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{DAOBLRAMT}_{o,(j,k)}$	$	*Day-Ahead Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for the PTP Obligation with Refund with the source *j* and the sink *k*, settled in the DAM, for the hour.
$\text{DAOBLRTP}_{o,(j,k)}$	$	*Day-Ahead Obligation with Refund Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Obligations with Refund, with the source *j* and the sink *k*, settled in the DAM, for the hour.
$\text{DAOBLRHV}_{o,(j,k)}$	$	*Day-Ahead Obligation with Refund Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Obligations with Refund, with the source *j* and the sink *k*, settled in the DAM, for the hour.
$\text{DAOBLRDA}_{o,(j,k)}$	$	*Day-Ahead Obligation with Refund Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Obligations with Refund, with the source *j* and the sink *k*, settled in the DAM, for the hour.
$\text{DAOBLPR}_{(j,k)}$	$/MW per hour	*Day-Ahead Obligation Price*—The DAM price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
DASPP_{j}	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j* for the hour.
DASPP_{k}	$/MWh	*Day-Ahead Settlement Point Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k* for the hour.
$\text{OBLDRPR}_{(j,k)}$	$/MW per hour	*Obligation Deration Price per source and sink pair*—The deration price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
DASP_{c}	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF_{c}	none	*Deration Factor per constraint*— The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.

Variable	Unit	Definition
$DAWASF_{j, c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the directional network element for constraint *c*, in the hour.
$DAWASF_{k, c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the directional network element for constraint *c*, in the hour.
$DAOBLHVPR_{(j, k)}$	$/MWh	*Day-Ahead Obligation Hedge Value Price per source and sink pair*—The Day-Ahead hedge price of a PTP Obligation with the source *j* and the sink *k*, for the hour.
$MINRESPR_{j}$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for Resources located at the source Settlement Point *j*.
$MAXRESPR_{k}$	$/MWh	*Max Resource Price for sink*—The highest Maximum Resource Price for Resources located at the sink Settlement Point *k*.
$DAOBLR_{o, (j, k)}$	MW	*Day-Ahead Obligation with Refund per CRR Owner per pair of source and sink*— The number of CRR Owner *o*'s PTP Obligations with Refund with the source *j* and the sink *k* settled in DAM for the hour.
$OBLRACT_{o, (j, k)}$	MW	*Obligation with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner *o*'s actual usage for the PTP Obligations with Refund with the source *j* and the sink *k*, for the hour.
$RESACT_{r, (j, k), y}$	MW	*Resource Actual per resource associated with pair of source and sink per interval*—The output of Resource *r* associated with the PTP Obligations with Refund with the source *j* and the sink *k*, for the Security-Constrained Economic Dispatch (SCED) interval y.
$OBLROF_{o, r, (j, k)}$	none	*Obligation with Refund Ownership Factor per CRR Owner per resource associated with pair of source and sink*—The factor showing the percentage usage of Resource *r* for CRR Owner *o*'s PTP Obligations with Refund with the source *j* and the sink *k*. Its value is 1, if only one CRR Owner has acquired Pre-Assigned Congestion Revenue Right (PCRRs) under the refund provision using this Resource *r*.
$OS_{r, y}$	MW	*Output Schedule per resource per SCED interval*—The Output Schedule for Resource *r* for the SCED interval y.
$EBP_{r, y}$	MW	*Emergency Base Point per resource per SCED interval*—The Emergency Base Point of Resource *r* for the SCED interval y.
$BP_{r, y}$	MW	*Base Point per resource per SCED interval*—The Base Point of Resource *r* for the SCED interval y.
$OBLRF_{o, (j, k)}$	none	*Obligation with Refund Factor associated with pair of source and sink per CRR Owner*—The ratio of CRR Owner *o*'s capacity allocated to the PTP Obligations with Refund with the source *j* and sink *k* to the same CRR Owner's total capacity nominated for all the PCRRs under the refund provision with the same source *j*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
o	none	A CRR Owner.
y	none	A SCED interval in the hour.
r	none	A Resource.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A constraint associated with a directional network element for the hour.

(4) The net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations with Refund settled in the DAM is calculated as follows:

$$\mathbf{DAOBLRAMTOTOT}_{\,o} = \mathbf{DAOBLRCROTOT}_{\,o} + \mathbf{DAOBLRCHOTOT}_{\,o}$$

Where:

$$\text{DAOBLRCROTOT}_{\,o} = \sum_{j} \sum_{k} \text{Min}\,(0, \text{DAOBLRAMT}_{\,o, (j, k)})$$

$$\text{DAOBLRCHOTOT}_{\,o} = \sum_{j} \sum_{k} \text{Max}\,(0, \text{DAOBLRAMT}_{\,o, (j, k)})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DAOBLRAMTOTOT $_o$	$	*Day-Ahead Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* for all its PTP Obligations with Refund settled in the DAM, for the hour.
DAOBLRCROTOT $_o$	$	*Day-Ahead Obligation with Refund Credit Owner Total per CRR Owner*—The total payment to CRR Owner *o* for its PTP Obligations with Refund settled in the DAM, for the hour.
DAOBLRCHOTOT $_o$	$	*Day-Ahead Obligation with Refund Charge Owner Total per CRR Owner*—The total charge to CRR Owner *o* for its PTP Obligations with Refund settled in the DAM, for the hour.
DAOBLRAMT $_{o, (j, k)}$	$	*Day-Ahead Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for the PTP Obligations with Refund with the source *j* and the sink *k* settled in the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.1.6 Payments for PTP Options with Refund Settled in DAM

(1) Except as specified otherwise in paragraph (2) below, ERCOT shall pay the owner of a PTP Option with Refund the difference in the DAM Settlement Point Prices between the sink Settlement Point and the source Settlement Point, if positive, subject to a charge for refund, as described in the item (e) (i) of Section 7.4.2, PCRR Allocation Terms and Conditions.

(2) The payment of PTP Options with Refund may be further reduced due to transmission elements that are oversold in previous CRR auctions.

(3) The payment to each CRR Owner for a given Operating Hour of its PTP Options with Refund with each pair of source and sink Settlement Points settled in the DAM is calculated as follows:

$$\mathbf{DAOPTRAMT}_{o,(j,k)} = \mathbf{(-1) * Max ((DAOPTRTP}_{o,(j,k)} - \mathbf{DAOPTRDA}_{o,(j,k)}\mathbf{), Min (DAOPTRTP}_{o,(j,k)}\mathbf{, DAOPTRHV}_{o,(j,k)}\mathbf{))}$$

Where:

The target payment:

$$\text{DAOPTRTP}_{o,(j,k)} = \text{DAOPTPR}_{(j,k)} * \text{Min}(\text{DAOPTR}_{o,(j,k)}, \text{OPTRACT}_{o,(j,k)} * \text{DAOPTR}_{o,(j,k)} / (\text{DAOPTR}_{o,(j,k)} + \text{RTOPTR}_{o,(j,k)}))$$

$$\text{DAOPTPR}_{(j,k)} = \text{Max}(0, \text{DASPP}_k - \text{DASPP}_j)$$

$$\text{OPTRACT}_{o,(j,k)} = \sum_y (\sum_r (\text{OPTROF}_{o,r,(j,k)} * \text{RESACT}_{r,(j,k),y}) * \text{TLMP}_y) / (\sum_y \text{TLMP}_y) * \text{OPTRF}_{o,(j,k)}$$

If ($\text{OS}_{r,y}$ exists)

$\text{RESACT}_{r,(j,k),y} = \text{OS}_{r,y}$

Otherwise

If ($\text{EBP}_{r,y}$ exists)

$\text{RESACT}_{r,(j,k),y} = \text{EBP}_{r,y}$

Otherwise

$\text{RESACT}_{r,(j,k),y} = \text{BP}_{r,y}$

The derated amount:

$$\text{DAOPTRDA}_{o,(j,k)} = \text{OPTDRPR}_{(j,k)} * \text{Min}(\text{DAOPTR}_{o,(j,k)}, \text{OPTRACT}_{o,(j,k)} * \text{DAOPTR}_{o,(j,k)} / (\text{DAOPTR}_{o,(j,k)} + \text{RTOPTR}_{o,(j,k)}))$$

$$\text{OPTDRPR}_{(j,k)} = \sum_c (\text{Max}(0, \text{DAWASF}_{j,c} - \text{DAWASF}_{k,c}) * \text{DASP}_c * \text{DRF}_c)$$

The hedge value:

$$\text{DAOPTRHV}_{o,(j,k)} = \text{DAOPTHVPR}_{(j,k)} * \text{Min}(\text{DAOPTR}_{o,(j,k)}, \text{OPTRACT}_{o,(j,k)} * \text{DAOPTR}_{o,(j,k)} / (\text{DAOPTR}_{o,(j,k)} + \text{RTOPTR}_{o,(j,k)}))$$

$$\text{DAOPTHVPR}_{(j,k)} = \text{Max}(0, \text{DASPP}_k - \text{MINRESPR}_j)$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{DAOPTRAMT}_{o,(j,k)}$	$	*Day-Ahead Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for its PTP Options with Refund with the

Variable	Unit	Definition
		source *j* and the sink *k*, settled in the DAM, for the hour.
DAOPTRTP $_{o, (j, k)}$	$	*Day-Ahead Option with Refund Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with Refund, with the source *j* and the sink *k*, settled in the DAM, for the hour.
DAOPTRHV $_{o, (j, k)}$	$	*Day-Ahead Option with Refund Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Options with Refund, with the source *j* and the sink *k*, settled in the DAM, for the hour.
DAOPTRDA $_{o, (j, k)}$	$	*Day-Ahead Option with Refund Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Options with Refund, with the source *j* and the sink *k*, settled in the DAM, for the hour.
DAOPTPR $_{(j, k)}$	$/MW per hour	*Day-Ahead Option Price per pair of source and sink*—The DAM price of the PTP Option with the source *j* and the sink *k*, for the hour.
DASPP $_{j}$	$/MWh	*Day-Ahead Settlement Point Price at source*—The DAM Settlement Point Price at the source Settlement Point *j*, for the hour.
DASPP $_{k}$	$/MWh	*Day-Ahead Settlement Pont Price at sink*—The DAM Settlement Point Price at the sink Settlement Point *k*, for the hour.
DAOPTR $_{o, (j, k)}$	MW	*Day-Ahead Option with Refund per CRR Owner per pair of source and sink*—The number of CRR Owner *o*'s PTP Options with Refund with the source *j* and the sink *k*, settled in DAM, for the hour.
RTOPTR $_{o, (j, k)}$	MW	*Real-Time Option with Refund per CRR Owner per pair of source and sink*—The number of CRR Owner *o*'s PTP Options with Refund with the source *j* and the sink *k* settled in Real-Time, for the hour.
OPTRACT $_{o, (j, k)}$	MW	*Option with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner *o*'s actual usage for the PTP Options with Refund with the source *j* and the sink *k*, for the hour.
RESACT $_{r, (j, k), y}$	MW	*Resource Actual per resource associated with pair of source and sink per interval*—The output of Resource *r* associated with the PTP Options with Refund with the source *j* and the sink *k*, for the SCED interval *y*.
OPTROF $_{o, r, (j, k)}$	none	*Option with Refund Ownership Factor per CRR Owner per resource associated with pair of source and sink*—The factor showing the percentage usage of Resource *r* for CRR Owner *o*'s PTP Options with Refund with the source *j* and the sink *k*. Its value is 1, if only one CRR Owner has acquired PCRRs under the refund provision using this Resource *r*.
OS $_{r, y}$	MW	*Output Schedule per resource per SCED interval*—The Output Schedule for Resource *r* for the SCED interval *y*.
EBP $_{r, y}$	MW	*Emergency Base Point per resource per SCED interval*—The Emergency Base Point of Resource *r* for the SCED interval *y*.
BP $_{r, y}$	MW	*Base Point per resource per SCED interval*—The Base Point of Resource *r* for the SCED interval *y*.
OPTRF $_{o, (j, k)}$	none	*Option with Refund Factor associated with pair of source and sink per CRR Owner*—The ratio of CRR Owner *o*'s capacity allocated to the PTP Options with Refund with the source *j* and sink *k* to the same CRR Owner's total capacity nominated PCRRs under the refund provision with the same source *j*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
OPTDRPR $_{(j, k)}$	$/MW per hour	*Option Deration Price per source and sink pair*—The deration price of a PTP Option with the source *j* and the sink *k*, for the hour.

Variable	Unit	Definition
DASP $_{c}$	\$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF $_{c}$	none	*Deration Factor per constraint*— The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
DAWASF $_{j,\,c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the directional network element for constraint *c*, in the hour.
DAWASF $_{k,\,c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the directional network element for constraint *c*, in the hour.
DAOPTHVPR $_{(j,\,k)}$	\$/MWh	*Day-Ahead Option Hedge Value Price per pair of source and sink*—The Day-Ahead hedge price of a PTP Option with the source *j* and the sink *k*, for the hour.
MINRESPR $_{j}$	\$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for Resources located at the source Settlement Point *j*.
o	none	A CRR Owner.
y	none	A SCED interval in the hour.
r	none	A Resource.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A constraint associated with a directional network element for the hour.

(4) The total payment to each Non-Opt-In-Entity (NOIE) CRR Owner for the Operating Hour of all its PTP Options with Refund settled in the DAM is calculated as follows:

$$\textbf{DAOPTRAMTOTOT}_{\,o} = \sum_{j} \sum_{k} \textbf{DAOPTRAMT}_{\,o,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
DAOPTRAMTOTOT $_{o}$	\$	*Day-Ahead Option with Refund Amount Owner Total per CRR Owner*—The total payment to NOIE CRR Owner *o* for all its PTP Options with Refund settled in the DAM, for the hour.
DAOPTRAMT $_{o,\,(j,\,k)}$	\$	*Day-Ahead Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to NOIE CRR Owner *o* for the PTP Options with Refund with the source *j* and the sink *k* settled in the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.2 Real-Time CRR Payments and Charges

7.9.2.1 Payments and Charges for PTP Obligations Settled in Real-Time

(1) ERCOT shall pay or charge the Qualified Scheduling Entity (QSE) of each PTP Obligation acquired in the DAM the difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment or charge to each QSE for a given Operating Hour of its cleared PTP Obligations with each pair of source and sink Settlement Points is calculated as follows:

$$\textbf{RTOBLAMT}_{q,(j,k)} = \textbf{(-1) * RTOBLPR}_{(j,k)} \textbf{ * RTOBL}_{q,(j,k)}$$

(2) In the event that ERCOT is unable to execute the DAM, ERCOT shall pay or charge the owner of each PTP Obligation based on the difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment or charge to each CRR Owner for a given Operating Hour of its PTP Obligations with each pair of source and sink Settlement Points is calculated as follows:

$$\textbf{NDRTOBLAMT}_{o,(j,k)} = \textbf{(-1) * RTOBLPR}_{(j,k)} \textbf{ * DAOBL}_{o,(j,k)}$$

Where:

$$\text{RTOBLPR}_{(j,k)} = \sum_{i=1}^{4} (\text{RTSPP}_{k,i} - \text{RTSPP}_{j,i}) / 4$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{RTOBLAMT}_{q,(j,k)}$	\$	*Real-Time Obligation Amount per QSE per pair of source and sink*—The payment or charge to QSE *q* for its PTP Obligations with the source *j* and the sink *k* settled in Real-Time, for the hour.
$\text{NDRTOBLAMT}_{o,(j,k)}$	\$	*No DAM Real-Time Obligation Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for its PTP Obligations with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\text{RTOBLPR}_{(j,k)}$	\$/MW per hour	*Real-Time Obligation Price*—The Real-Time price of the PTP Obligation, for the hour.
$\text{RTSPP}_{j,i}$	\$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source *j* for the 15-minute Settlement Interval *i*.
$\text{RTSPP}_{k,i}$	\$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink *k* for the 15-minute Settlement Interval *i*.
$\text{RTOBL}_{q,(j,k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The number of QSE *q*'s PTP Obligations for the source *j* and the sink *k* settled in Real-Time for the hour.
$\text{DAOBL}_{o,(j,k)}$	MW	*Day-Ahead Obligation per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Obligations with the source *j* and the sink *k* settled in the DAM for the hour. See Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM.

Variable	Unit	Definition
o	none	A CRR Owner.
q	none	A QSE.
i	none	A 15-minute Settlement Interval in the Operating Hour.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(3) The net total payment or charge to each QSE for the Operating Hour of all its PTP Obligations settled in Real-Time is calculated as follows:

$$\textbf{RTOBLAMTQSETOT}_{q} = \sum_{j} \sum_{k} \textbf{RTOBLAMT}_{q, (j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{RTOBLAMTQSETOT}_{q}$	\$	*Real-Time Obligation Amount QSE Total per QSE*—The net total payment or charge to QSE *q* of all its PTP Obligations settled in Real-Time, for the hour.
$\text{RTOBLAMT}_{q, (j, k)}$	\$	*Real-Time Obligation Amount per QSE per pair of source and sink*—The payment or charge to QSE *q* for the PTP Obligations with the source *j* and the sink *k* settled in Real-Time, for the hour.
q	none	A QSE.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(4) If ERCOT is unable to execute DAM, the net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations settled in Real-Time is calculated as follows:

$$\textbf{NDRTOBLAMTOTOT}_{o} = \sum_{j} \sum_{k} \textbf{NDRTOBLAMT}_{o,(j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{NDRTOBLAMTOTOT}_{o}$	\$	*No DAM Real-Time Obligation Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* of all its PTP Obligations settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\text{NDRTOBLAMT}_{o, (j, k)}$	\$	*No DAM Real-Time Obligation Amount per CRR Owner per pair of source and sink*—The payment or charge to CRR Owner *o* for its PTP Obligations with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
o	None	A CRR Owner.
j	None	A source Settlement Point.
k	None	A sink Settlement Point.

7.9.2.2 Payments for PTP Options Settled in Real-Time

(1) Except as specified in paragraphs (2) and (3) below, ERCOT shall pay the NOIE that owns a PTP Option that was declared before DAM execution by the NOIE to be settled in Real-Time and not cleared in the DAM, the positive difference in Real-Time Settlement Point Prices between the sink and the source.

(2) For PTP Options that source or sink at a Resource Node, the PTP Option payment may be reduced due to transmission elements that are oversold in previous CRR auctions.

(3) When the DAM is not executed, ERCOT shall pay the owner of each PTP Option based on the positive difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. ERCOT shall not reduce the PTP Option payment as specified in paragraph (2) above due to transmission elements that are oversold in previous CRR auctions. The payment to each CRR Owner for a given Operating Hour of its PTP Options with each pair of source and sink Settlement Points is calculated as follows:

$$\textbf{NDRTOPTAMT}_{\,o,\,(j,\,k)} = \textbf{(-1) * NDRTOPTTP}_{\,o,\,(j,\,k)}$$

Where:

The target payment if ERCOT is unable to execute the DAM:

$$\text{NDRTOPTTP}_{\,o,\,(j,\,k)} = \text{RTOPTPR}_{\,(j,\,k)} * \text{DAOPT}_{\,o,\,(j,\,k)}$$

(4) When the DAM is executed, the payment to each NOIE CRR Owner for a given Operating Hour of the PTP Options with each pair of source and sink Settlement Points settled in Real-Time is calculated as follows:

If the source, j, is a Load Zone or Hub and the sink, k, is also a Load Zone or Hub, then

$$\textbf{RTOPTAMT}_{\,o,\,(j,\,k)} = \textbf{(-1) * RTOPTTP}_{\,o,\,(j,\,k)}$$

If either the source, j, or the sink, k, is a Resource Node, then

$$\textbf{RTOPTAMT}_{\,o,\,(j,\,k)} = \textbf{(-1) * Max ((RTOPTTP}_{\,o,\,(j,\,k)} \textbf{ – RTOPTDA}_{\,o,\,(j,\,k)}\textbf{), Min (RTOPTTP}_{\,o,\,(j,\,k)}\textbf{, RTOPTHV}_{\,o,\,(j,\,k)}\textbf{))}$$

Where:

The target payment:

$$\text{RTOPTTP}_{\,o,\,(j,\,k)} = \text{RTOPTPR}_{\,(j,\,k)} * \text{RTOPT}_{\,o,\,(j,\,k)}$$

$$\text{RTOPTPR}_{\,(j,\,k)} = \sum_{i=1}^{4} \text{Max}\,(0, \text{RTSPP}_{\,k,\,i} – \text{RTSPP}_{\,j,\,i}) / 4$$

The derated amount:

$$RTOPTDA_{o,(j,k)} = OPTDRPR_{(j,k)} * RTOPT_{o,(j,k)}$$

$$OPTDRPR_{(j,k)} = \sum_{c} (Max(0, DAWASF_{j,c} - DAWASF_{k,c}) * DASP_{c} * DRF_{c})$$

The hedge value:

$$RTOPTHV_{o,(j,k)} = RTOPTHVPR_{(j,k)} * RTOPT_{o,(j,k)}$$

If the source, j, is a Load Zone or Hub and the sink, k, is a Resource Node,

$$RTOPTHVPR_{(j,k)} = \sum_{i=1}^{4} Max(0, MAXRESPR_{k} - RTSPP_{j,i}) / 4$$

If the source, j, is a Resource Node and the sink, k, is a Load Zone or Hub,

$$RTOPTHVPR_{(j,k)} = \sum_{i=1}^{4} Max(0, RTSPP_{k,i} - MINRESPR_{j}) / 4$$

If the source, j, is a Resource Node and the sink, k, is also a Resource Node,

$$RTOPTHVPR_{(j,k)} = Max(0, MAXRESPR_{k} - MINRESPR_{j})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$RTOPTAMT_{o,(j,k)}$	\$	*Real-Time Option Amount per CRR Owner per source and sink pair* —The payment to NOIE CRR Owner *o* of PTP Options with the source *j* and the sink *k* settled in Real-Time, for the hour.
$NDRTOPTAMT_{o,(j,k)}$	\$	*No DAM Real-Time Option Amount per CRR Owner per source and sink pair* —The payment to CRR Owner *o* of PTP Options with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$RTOPTTP_{o,(j,k)}$	\$	*Real-Time Option Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in Real-Time, for the hour.
$NDRTOPTTP_{o,(j,k)}$	\$	*No DAM Real-Time Option Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$RTOPTHV_{o,(j,k)}$	\$	*Real-Time Option Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in Real-Time, for the hour.
$RTOPTDA_{o,(j,k)}$	\$	*Real-Time Option Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in Real-Time, for the hour.
$RTOPTPR_{(j,k)}$	\$/MW per hour	*Real-Time Option Price per source and sink pair* —The Real-Time price of a PTP Option with the source *j* and the sink *k* for the hour.
$RTSPP_{j,i}$	\$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source Settlement Point *j*, for the 15-minute Settlement Interval *i*.
$RTSPP_{k,i}$	\$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink Settlement Point *k*, for the 15-minute Settlement Interval *i*.

Variable	Unit	Definition
OPTDRPR $_{(j, k)}$	$/MW per hour	*Option Deration Price per source and sink pair*—The deration price of a PTP Option with the source *j* and the sink *k*, for the hour.
DASP $_c$	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF $_c$	none	*Deration Factor per constraint*— The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
DAWASF $_{j, c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the constrained directional network element for constraint *c*, in the hour.
DAWASF $_{k, c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the constrained directional network element for constraint *c*, in the hour.
RTOPTHVPR $_{(j, k)}$	$/MWh	*Real-Time Option Hedge Value Price per source and sink pair*—The Day-Ahead hedge price of a PTP Option with the source *j* and the sink *k*, for the hour.
MINRESPR $_j$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for Resources located at the source Settlement Point *j*.
MAXRESPR $_k$	$/MWh	*Max Resource Price for sink*—The highest Maximum Resource Price for Resources located at the sink Settlement Point *k*.
RTOPT $_{o, (j, k)}$	MW	*Real-Time Option per CRR Owner per pair of source and sink*—The number of NOIE CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in Real-Time for the hour.
DAOPT $_{o, (j, k)}$	MW	*Day-Ahead Option per CRR Owner per source and sink pair*—The number of CRR Owner *o*'s PTP Options with the source *j* and the sink *k* settled in the DAM for the hour. See Section 7.9.1.2, Payments for PTP Options Settled in DAM.
o	none	A CRR Owner.
i	none	A 15-minute Settlement Interval in the Operating Hour.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A DAM constraint associated with a directional network element for the hour.

(5) The total payment to each NOIE CRR Owner for the Operating Hour of all its PTP Options settled in Real-Time is calculated as follows:

$$\textbf{RTOPTAMTOTOT}_{\,o} \quad = \quad \sum_{j}\sum_{k} \textbf{RTOPTAMT}_{\,o, (j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTOPTAMTOTOT $_o$	$	*Real-Time Option Amount Owner Total per CRR Owner*—The total payment to NOIE CRR Owner *o* for all its PTP Options settled in Real-Time, for the hour.
RTOPTAMT $_{o, (j, k)}$	$	*Real-Time Option Amount per CRR Owner per pair of source and sink*—The payment to NOIE CRR Owner *o* for its PTP Options with the source *j* and the sink *k* settled in Real-Time, for the hour.
o	none	A CRR Owner.

j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(6) If ERCOT is unable to execute the DAM, the total payment to each CRR Owner for the Operating Hour of all its PTP Options settled in Real-Time is calculated as follows:

$$\mathbf{NDRTOPTAMTOTOT}_{\,o} = \sum_{j} \sum_{k} \mathbf{NDRTOPTAMT}_{\,o,\,(j,\,k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
NDRTOPTAMTOTOT $_{o}$	$	*No DAM Real-Time Option Amount Owner Total per CRR Owner*—The total payment to CRR Owner *o* for all its PTP Options settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTAMT $_{o, (j, k)}$	$	*No DAM Real-Time Option Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for its PTP Options with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(7) For informational purposes, the following calculation of PTP Option value shall be posted on the MIS Public Area:

$$\mathbf{RTOPTPRINFO}_{\,(j,\,k)} = \sum_{c} \left[\sum_{y} \left(\mathbf{RTSP}_{\,c,\,y} * \mathbf{Max}\,(0, \mathbf{RTWASF}_{\,j,\,c,\,y} - \mathbf{RTWASF}_{\,k,\,c,\,y}) * \mathbf{TLMP}_{\,y}\right) / \left(\sum_{y} \mathbf{TLMP}_{\,y}\right)\right]$$

The above variables are defined as follows:

Variable	Unit	Definition
RTOPTPRINFO $_{(j, k)}$	$/MW per hour	*Real-Time Option Price per pair of source and sink*—The Real-Time price of the PTP Options with the source Settlement Point *j* and the sink Settlement Point *k*, for the hour.
RTWASF $_{j, c, y}$	none	*Real-Time Weighted Average Shift Factor at source per constraint per SCED interval*—The Real-Time Shift Factor for the source Settlement Point and for the constrained directional network element for constraint *c*, in the SECD interval *y*.
RTWASF $_{k, c, y}$	none	*Real-Time Weighted Average Shift Factor at sink per constraint per SCED interval*—The Real-Time Shift Factor for the sink Settlement Point and for the constrained directional network element for constraint *c*, in the SCED interval *y*.
RTSP $_{c, y}$	$/MW per hour	*Real-Time Shadow Price per constraint per SCED interval*—The Real-Time Shadow Price for the constraint *c* in the SCED interval *y*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
c	none	A constraint associated with a directional network element for the hour
y	none	A SCED interval in the hour.

7.9.2.3 Payments for NOIE PTP Options with Refund Settled in Real-Time

(1) Except as specified in paragraphs (2) and (3) below, ERCOT shall pay the NOIE that owns a PTP Option with Refund that was allocated to that NOIE as a PCRR and that was, declared before DAM execution by the NOIE to be settled in Real-Time but not cleared in the DAM, for the MW quantity up to the pro-rata actual usage based on the positive difference in Real-Time Settlement Point Price between the sink and the source.

(2) The payment of PTP Options with Refund may be further reduced due to transmission elements that are oversold in previous CRR auctions.

(3) When the DAM is not executed, ERCOT shall pay the NOIE owner of each PTP Option with Refund that was allocated to that NOIE as a PCRR, for the quantity up to the actual usage based on the positive difference in Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. ERCOT shall not reduce the PTP Options with Refund payment as specified in paragraph (2) above due to transmission elements that are oversold in previous CRR auctions. The payment to each NOIE CRR Owner for a given Operating Hour of its PTP Options with Refund each pair of source and sink Settlement Points is calculated as follows:

$$\mathbf{NDRTOPTRAMT}_{o,(j,k)} = \mathbf{(-1) * NDRTOPTRTP}_{o,(j,k)}$$

Where:

The target payment if ERCOT is unable to execute the DAM:

$$\text{NDRTOPTRTP}_{o,(j,k)} = \text{RTOPTRPR}_{(j,k)} * \text{Min}(\text{DAOPTR}_{o,(j,k)},\ \text{OPTRACT}_{o,(j,k)})$$

(4) When the DAM is executed, the payment to each NOIE CRR Owner for a given Operating Hour of the PTP Options with Refund with each pair of source and sink Settlement Points settled in Real-Time is calculated as follows:

$$\mathbf{RTOPTRAMT}_{o,(j,k)} = \mathbf{(-1) * Max((RTOPTRTP}_{o,(j,k)} \mathbf{- RTOPTRDA}_{o,(j,k)}\mathbf{), Min(RTOPTRTP}_{o,(j,k)}\mathbf{, RTOPTRHV}_{o,(j,k)}\mathbf{))}$$

Where:

The target payment:

$$\text{RTOPTRTP}_{o,(j,k)} = \text{RTOPTPR}_{(j,k)} * \text{Min}(\text{RTOPTR}_{o,(j,k)},\ (\text{OPTRACT}_{o,(j,k)} * \text{RTOPTR}_{o,(j,k)} / (\text{RTOPTR}_{o,(j,k)} + \text{DAOPTR}_{o,(j,k)})))$$

$$\text{RTOPTPR}_{(j,k)} = \sum_{i=1}^{4} \text{Max}(0,\ \text{RTSPP}_{k,i} - \text{RTSPP}_{j,i}) / 4$$

$$\text{OPTRACT}_{o,(j,k)} = \sum_{y} (\sum_{r} (\text{OPTROF}_{o,r,(j,k)} * \text{RESACT}_{r,(j,k),y}) * \text{TLMP}_{y}) / (\sum_{y} \text{TLMP}_{y}) * \text{OPTRF}_{o,(j,k)}$$

If ($\text{OS}_{r,y}$ exists)

$\text{RESACT}_{r,(j,k),y} = \text{OS}_{r,y}$

Otherwise

If ($\text{EBP}_{r,y}$ exists)

$\text{RESACT}_{r,(j,k),y} = \text{EBP}_{r,y}$

Otherwise

$\text{RESACT}_{r,(j,k),y} = \text{BP}_{r,y}$

The derated amount:

$$\text{RTOPTRDA}_{o,(j,k)} = \text{OPTDRPR}_{(j,k)} * \text{Min}(\text{RTOPTR}_{o,(j,k)}, (\text{OPTRACT}_{o,(j,k)} * \text{RTOPTR}_{o,(j,k)} / (\text{RTOPTR}_{o,(j,k)} + \text{DAOPTR}_{o,(j,k)})))$$

$$\text{OPTDRPR}_{(j,k)} = \sum_{c} (\text{Max}(0, \text{DAWASF}_{j,c} - \text{DAWASF}_{k,c}) * \text{DASP}_{c} * \text{DRF}_{c})$$

The hedge value:

$$\text{RTOPTRHV}_{o,(j,k)} = \text{RTOPTHVPR}_{(j,k)} * \text{Min}(\text{RTOPTR}_{o,(j,k)}, (\text{OPTRACT}_{o,(j,k)} * \text{RTOPTR}_{o,(j,k)} / (\text{RTOPTR}_{o,(j,k)} + \text{DAOPTR}_{o,(j,k)})))$$

$$\text{RTOPTHVPR}_{(j,k)} = \text{Max}(0, \text{RTSPP}_{k} - \text{MINRESPR}_{j})$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{RTOPTRAMT}_{o,(j,k)}$	$	*Real-Time Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* of the PTP Options with Refund with the source *j* and the sink *k*, settled in Real-Time, for the hour.
$\text{NDRTOPTRAMT}_{o,(j,k)}$	$	*No DAM Real-Time Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* of the PTP Options with Refund with the source *j* and the sink *k*, settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\text{RTOPTRTP}_{o,(j,k)}$	$	*Real-Time Option with Refund Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with Refund, with the source *j* and the sink *k*, settled in Real-Time, for the hour.
$\text{NDRTOPTRTP}_{o,(j,k)}$	$	*No DAM Real-Time Option with Refund Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Options with Refund, with the source *j* and the sink *k*, settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
$\text{RTOPTRHV}_{o,(j,k)}$	$	*Real-Time Option with Refund Hedge Value per CRR Owner per source and sink pair*—The hedge value of CRR Owner *o*'s PTP Options with Refund, with the source *j* and the sink *k*, settled in Real-Time, for the hour.

Variable	Unit	Definition
$RTOPTRDA_{o, (j, k)}$	$	*Real-Time Option with Refund Derated Amount per CRR Owner per source and sink pair*—The derated amount of CRR Owner *o*'s PTP Options with Refund, with the source *j* and the sink *k*, settled in Real-Time, for the hour.
$RTOPTPR_{(j, k)}$	$/MW per hour	*Real-Time Option Price per pair of source and sink*—The Real-Time price of the PTP Options with the source *j* and the sink *k*, for the hour.
$RTSPP_{j, i}$	$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source *j* for the 15-minute Settlement Interval *i*.
$RTSPP_{k, i}$	$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink *k* for the 15-minute Settlement Interval *i*.
$OPTRACT_{o, (j, k)}$	MW	*Option with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner *o*'s actual usage for the PTP Options with Refund with the source *j* and the sink *k*, for the hour.
$RESACT_{r, (j, k), y}$	MW	*Resource Actual per resource associated with pair of source and sink per interval*—The output of Resource *r* recognized for the CRR Owner's PTP Options with Refund with the source *j* and the sink *k*, for the SCED interval y.
$OPTROF_{o, r, (j, k)}$	none	*Option with Refund Ownership Factor per CRR Owner per resource associated with pair of source and sink*—The factor showing the percentage usage of Resource *r* for CRR Owner *o*'s PTP Options with Refund with the source *j* and the sink *k*. Its value is 1, if only one CRR Owner uses this Resource for PCRRs under the refund provision.
$OS_{r, y}$	MW	*Output Schedule per resource per SCED interval*—The Output Schedule for Resource *r* for the SCED interval *y*.
$EBP_{r, y}$	MW	*Emergency Base Point per resource per SCED interval*—The Emergency Base Point of Resource *r* for the SCED interval *y*.
$BP_{r, y}$	MW	*Base Point per resource per SCED interval*—The Base Point of Resource *r* for the SCED interval *y*.
$OPTRF_{o, (j, k)}$	none	*Option with Refund Factor associated with pair of source and sink per CRR Owner*—The ratio of CRR Owner *o*'s capacity allocated to the PTP Options with Refund with the source *j* and sink *k* to the same CRR Owner's total capacity nominated for all the PCRRs under the refund provision with the same source *j*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
$RTOPTR_{(j, k)}$	MW	*Real-Time Option with Refund per pair of source and sink*—The number of the CRR Owner's PTP Options with Refund with the source *j* and the sink *k*, settled in Real-Time, for the hour.
$DAOPTR_{o, (j, k)}$	MW	*Day-Ahead Option with Refund per CRR Owner per pair of source and sink*—The number of CRR Owner *o*'s PTP Options with Refund settled in the DAM for the hour.
$OPTDRPR_{(j, k)}$	$/MW per hour	*Option Deration Price per source and sink pair*—The deration price of a PTP Option with the source *j* and the sink *k*, for the hour.
$DASP_{c}$	$/MW per hour	*Day-Ahead Shadow Price per constraint*—The DAM Shadow Price of the constraint *c* for the hour.
DRF_{c}	none	*Deration Factor per constraint*— The deration factor of the constraint *c* for the hour, equal to the MW amount by which the constraint is oversold divided by the total MW amount of the positive impacts on the constraint of all CRRs existing prior to DAM execution.
$DAWASF_{j, c}$	none	*Day-Ahead Weighted Average Shift Factor at source per constraint*—The Day-Ahead Shift Factor for the source Settlement Point and the directional network element for constraint *c*, in the hour.

Variable	Unit	Definition
DAWASF $_{k, c}$	none	*Day-Ahead Weighted Average Shift Factor at sink per constraint*—The Day-Ahead Shift Factor for the sink Settlement Point and the directional network element for constraint *c*, in the hour.
RTOPTHVPR $_{(j, k)}$	$/MWh	*Real-Time Option Hedge Value Price per source and sink pair*—The Real-Time hedge price of a PTP Option with the source *j* and the sink *k*, for the hour.
MINRESPR $_{j}$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for Resources located at the source Settlement Point *j*.
o	none	A CRR Owner.
r	none	A Resource.
y	none	A SCED interval in the hour.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
c	none	A constraint associated with a directional network element for the hour.

(5) The total payment to each NOIE CRR Owner for the Operating Hour of all its PTP Options with Refund settled in Real-Time is calculated as follows:

$$\mathbf{RTOPTRAMTOTOT}_{\ o} = \sum_{j} \sum_{k} \mathbf{RTOPTRAMT}_{\ o,\ (j,\ k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTOPTRAMTOTOT $_{o}$	$	*Real-Time Option with Refund Amount Owner Total per CRR Owner*—The total payment to NOIE CRR Owner *o* for all its PTP Options with Refund settled in Real-Time, for the hour.
RTOPTRAMT $_{o, (j, k)}$	$	*Real-Time Option with Refund Amount per CRR Owner per pair of source and sink*—The payment to NOIE CRR Owner *o* for the PTP Options with Refund with the source *j* and the sink *k* settled in Real-Time, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(6) If ERCOT is unable to execute the DAM, the total payment to each NOIE CRR Owner for the Operating Hour of all its PTP Options with Refund settled in Real-Time is calculated as follows:

$$\mathbf{NDRTOPTRAMTOTOT}_{\ o} = \sum_{j} \sum_{k} \mathbf{NDRTOPTRAMT}_{\ o,\ (j,\ k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
NDRTOPTRAMTOTOT $_{o}$	$	*No DAM Real-Time Option with Refund Amount Owner Total per CRR Owner*—The total payment to NOIE CRR Owner *o* for all its PTP Options with Refund settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTOPTRAMT $_{o, (j, k)}$	$	*No DAM Real-Time Option with Refund Amount per CRR Owner per pair of*

Variable	Unit	Definition
		source and sink—The payment to NOIE CRR Owner *o* for the PTP Options with Refund with the source *j* and the sink *k* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.2.4 Payments for FGRs in Real-Time

(1) In the event that ERCOT is unable to execute the DAM, ERCOT shall pay the owner of the FGR an amount based on the time-weighted Shadow Price of each SCED interval for each directional network element associated with the FGR for each contingency (including the null contingency or base case) normalized to the impact of the principal network element of the FGR (the normal rating of which is used to determine the total MW amount for the flowgate). The payment to each CRR Owner for its FGRs determined by the principle network element of each flowgate for a given hour is calculated as follows:

$$\text{NDRTFGRAMT}_{o,f} = \mathbf{(-1)} ^{*} \mathbf{NDRTFGRTP}_{o,f}$$

Where:

$$\text{NDRTFGRTP}_{o,f} = \text{NDRTFGRPR}_{f} {}^{*}\ \text{DAFGR}_{o,f}$$

$$\text{NDRTFGRPR}_{f} = \sum_{y} \sum_{e \in f} (INF_{f,e} * \sum_{c} RTSP_{e,c,y}) * TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Definition
NDRTFGRAMT $_{o,f}$	$	*No DAM Real-Time FGR Amount per CRR Owner per flowgate*—The payment to CRR Owner *o* of the flowgate *f* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTFGRTP $_{o,f}$	$	*No DAM Real-Time FGR Target Payment per CRR Owner per flowgate*—The target payment for CRR Owner *o*'s flowgate *f* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTFGRPR $_{f}$	$/MW per hour	*No DAM Real-Time FGR Price per flowgate*—The Real-Time price of the flowgate *f* when ERCOT is unable to execute DAM, for the hour.
RTSP $_{e,c,y}$	$/MW per hour	*Real-Time Shadow Price per element per constraint per SCED interval*—The Real-Time Shadow Price on the directional network element *e*, for constraint *c*, in the SCED interval y.
TLMP $_{y}$	second	Duration of SCED interval per interval—The duration of the portion of the SCED interval *y* within the hour.
INF $_{f,e}$	none	*Impact Normalization Factor per element per flowgate*—The parameter that reflects the normalized impact on the directional network element *e* relative to the impact on the principal network element of flowgate *f*.

Variable	Unit	Definition
DAFGR $_{o, f}$	MW	*Day-Ahead FGR per CRR Owner per flowgate*—The CRR Owner *o*'s total number of FGRs determined by the principle element of flowgate *f* settled in the DAM for the hour. See Section 7.9.1.4, Payments for FGRs Settled in DAM.
o	none	A CRR Owner.
f	none	A flowgate.
e	none	A directional network element.
c	none	A constraint.
$e \in f$	none	The directional network element *e* belongs to the flowgate *f*.
y	none	A SCED interval in the hour.

(2) If ERCOT is unable to execute the DAM, the total of the payments to each CRR Owner for the Operating Hour of all its FGRs settled in Real-Time is calculated as follows:

$$\mathbf{NDRTFGRAMTOTOT}_{\,o} = \sum_{f} \mathbf{NDRTFGRAMT}_{\,o,\,f}$$

The above variables are defined as follows:

Variable	Unit	Definition
NDRTFGRAMTOTOT $_{o}$	$	*No DAM Real-Time FGR Amount Owner Total per CRR Owner*—The total payment to CRR Owner *o* of all its FGRs settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
NDRTFGRAMT $_{o, f}$	$	*No DAM Real-Time FGR Amount per CRR Owner per flowgate*—The payment to CRR Owner *o* of the flowgate *f* settled in Real-Time when ERCOT is unable to execute the DAM, for the hour.
o	none	A CRR Owner.
f	none	A flowgate.

7.9.2.5 Payments and Charges for PTP Obligations with Refund in Real-Time

(1) In the event that ERCOT is unable to execute the DAM, ERCOT shall pay or charge the NOIE owner of a PTP Obligation with Refund, for the quantity up to the actual usage based on the difference in the Real-Time Settlement Point Prices between the sink Settlement Point and the source Settlement Point. The payment or charge to each NOIE CRR Owner for a given Operating Hour of its PTP Options with Refund each pair of source and sink Settlement Points in Real-Time is calculated as follows:

$$\mathbf{NDRTOBLRAMT}_{\,o,\,(j,\,k)} = \mathbf{(-1) * NDRTOBLRTP}_{\,o,\,(j,\,k)}$$

Where:

The target payment:

$$\text{NDRTOBLRTP}_{\,o,\,(j,\,k)} = \text{RTOBLRPR}_{\,(j,\,k)} * \text{Min}\,(\text{DAOBLR}_{\,o,\,(j,\,k)},\ \text{OBLRACT}_{\,o,\,(j,\,k)})$$

$$\text{RTOBLPR}_{(j,\,k)} \quad = \quad \sum_{i=1}^{4} (\text{RTSPP}_{k,\,i} - \text{RTSPP}_{j,\,i}) / 4$$

$$\text{OBLRACT}_{o,\,(j,\,k)} \quad = \quad \sum_{y} (\sum_{r} (\text{OBLROF}_{o,\,r,\,(j,\,k)} * \text{RESACT}_{r,\,(j,\,k),\,y}) * \text{TLMP}_{y}) / (\sum_{y} \text{TLMP}_{y}) * \text{OBLRF}_{o,\,(j,\,k)}$$

If ($OS_{r,\,y}$ exists)

$$\text{RESACT}_{r,\,(j,\,k),\,y} \quad = \quad \text{OS}_{r,\,y}$$

Otherwise

If ($EBP_{r,\,y}$ exists)

$$\text{RESACT}_{r,\,(j,\,k),\,y} \quad = \quad \text{EBP}_{r,\,y}$$

Otherwise

$$\text{RESACT}_{r,\,(j,\,k),\,y} \quad = \quad \text{BP}_{r,\,y}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
$\text{NDRTOBLRAMT}_{o,\,(j,\,k)}$	$	*No DAM Real-Time Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for the PTP Obligation with Refund with the source *j* and the sink *k*, settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
$\text{NDRTOBLRTP}_{o,\,(j,\,k)}$	$	*No DAM Real-Time Obligation with Refund Target Payment per CRR Owner per source and sink pair*—The target payment for CRR Owner *o*'s PTP Obligations with Refund, with the source *j* and the sink *k*, settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
$\text{RTOBLPR}_{(j,\,k)}$	$/MW per hour	*Real-Time Obligation Price*—The Real-Time price of the PTP Obligation, for the hour.
$\text{RTSPP}_{j,\,i}$	$/MWh	*Real-Time Settlement Point Price at source per interval*—The Real-Time Settlement Point Price at the source *j* for the 15-minute Settlement Interval *i*.
$\text{RTSPP}_{k,\,i}$	$/MWh	*Real-Time Settlement Point Price at sink per interval*—The Real-Time Settlement Point Price at the sink *k* for the 15-minute Settlement Interval *i*.
$\text{DAOBLR}_{o,\,(j,\,k)}$	MW	*Day-Ahead Obligation with Refund per CRR Owner per pair of source and sink*— The number of CRR Owner *o*'s PTP Obligations with Refund with the source *j* and the sink *k* settled in DAM for the hour. See Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM.
$\text{OBLRACT}_{o,\,(j,\,k)}$	MW	*Obligation with Refund Actual usage per CRR Owner per pair of source and sink*—CRR Owner *o*'s actual usage for the PTP Obligations with Refund with the source *j* and the sink *k*, for the hour.
$\text{RESACT}_{r,\,(j,\,k),\,y}$	MW	*Resource Actual per resource associated with pair of source and sink per interval*—The output of Resource *r* associated with the PTP Obligations with Refund with the source *j* and the sink *k*, for the SCED interval *y*.
$\text{OBLROF}_{o,\,r,\,(j,\,k)}$	none	*Obligation with Refund Ownership Factor per CRR Owner per resource associated with pair of source and sink*—The factor showing the percentage usage of Resource *r* for CRR Owner *o*'s PTP Obligations with Refund with the source *j* and the sink *k*. Its value is 1, if only one CRR Owner has acquired PCRRs under the refund provision using this Resource *r*.

Variable	Unit	Definition
$OS_{r, y}$	MW	*Output Schedule per resource per SCED interval*—The Output Schedule for Resource *r* for the SCED interval *y*.
$EBP_{r, y}$	MW	*Emergency Base Point per resource per SCED interval*—The Emergency Base Point of Resource *r* for the SCED interval *y*.
$BP_{r, y}$	MW	*Base Point per resource per SCED interval*—The Base Point of Resource *r* for the SCED interval *y*.
$OBLRF_{o, (j, k)}$	none	*Obligation with Refund Factor associated with pair of source and sink per CRR Owner*—The ratio of CRR Owner *o*'s capacity allocated to the PTP Obligations with Refund with the source *j* and sink *k* to the same CRR Owner's total capacity nominated for all the PCRRs under the refund provision with the same source *j*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the hour.
o	none	A CRR Owner.
y	none	A SCED interval in the hour.
r	none	A Resource.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

(2) If ERCOT is unable to execute the DAM, the net total payment or charge to each CRR Owner for the Operating Hour of all its PTP Obligations with Refund settled in Real-Time is calculated as follows:

$$\textbf{NDRTOBLRAMTOTOT}_{\,o} = \sum_{j} \sum_{k} \textbf{NDRTOBLRAMT}_{\,o, (j, k)}$$

The above variables are defined as follows:

Variable	Unit	Definition
$NDRTOBLRAMTOTOT_{o}$	$	*No DAM Real-Time Obligation with Refund Amount Owner Total per CRR Owner*—The net total payment or charge to CRR Owner *o* for all its PTP Obligations with Refund settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
$NDRTOBLRAMT_{o, (j, k)}$	$	*No DAM Real-Time Obligation with Refund Amount per CRR Owner per pair of source and sink*—The payment to CRR Owner *o* for the PTP Obligation with Refund with the source *j* and the sink *k*, settled in Real-Time, when ERCOT is unable to execute the DAM, for the hour.
o	none	A CRR Owner.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.

7.9.3 CRR Balancing Account

7.9.3.1 DAM Congestion Rent

(1) The DAM Congestion Rent is calculated as the sum of the following payments and charges:

(a) The total of payments to all QSEs for cleared DAM energy offers (this does not include any revenue calculated for an RMR Unit, even though its Three-Part Supply Offer was cleared in the DAM), whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves, calculated under Section 4.6.2.1., Day-Ahead Energy Payment;

(b) The total of revenue for all RMR Units as calculated below;

(c) The total of charges to all QSEs for cleared DAM Energy Bids, calculated under Section 4.6.2.2, Day-Ahead Energy Charge; and

(d) The total of charges or payments to all QSEs for PTP Obligation Bids cleared in the DAM, calculated under Section 4.6.3, Settlement for PTP Obligations Bought in DAM.

(2) The DAM Congestion Rent for a given Operating Hour is calculated as follows:

$$\mathbf{DACONGRENT} = \mathbf{DAESAMTTOT + RMRDAEREVTOT + DAEPAMTTOT + DARTOBLAMTTOT}$$

Where:

$$\text{DAESAMTTOT} = \sum_{q} \text{DAESAMTQSETOT}_{q}$$

$$\text{DAEPAMTTOT} = \sum_{q} \text{DAEPAMTQSETOT}_{q}$$

$$\text{DARTOBLAMTTOT} = \sum_{q} \text{DARTOBLAMTQSETOT}_{q}$$

$$\text{RMRDAEREVTOT} = \sum_{q} \sum_{p} \sum_{r} \text{DAEREV}_{q,\,p,\,r}$$

$$\text{DAEREV}_{q,\,p,\,r} = (-1) * \text{DASPP}_{p} * \text{DAESR}_{q,\,p,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
DACONGRENT	$	*Day-Ahead Congestion Rent*—The Congestion Rent collected in the DAM for the hour.

Variable	Unit	Definition
DAESAMTTOT	$	*Day-Ahead Energy Sale Amount Total*—The total payment to all QSEs for cleared DAM energy offers, whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves for the hour.
RMRDAEREVTOT	$	*RMR Day-Ahead Energy Revenue Total*—The total of the RMR Day-Ahead Energy Revenue for all RMR Units for the hour. See Section 6.6.6, Reliability Must-Run Settlement.
DAEPAMTTOT	$	*Day-Ahead Energy Purchase Amount Total*—The total charge to all QSEs for cleared DAM Energy Bids for the hour.
DARTOBLAMTTOT	$	*Day-Ahead Real-Time Obligation Amount Total*—The net total charge or payment to all QSEs for cleared PTP Obligation Bids in the DAM for the hour.
DAESAMTQSETOT $_{q}$	$	*Day-Ahead Energy Sale Amount QSE Total per QSE*—The total payment to QSE *q* for cleared DAM energy offers, whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves, for the hour. See Section 4.6.2.1, Day-Ahead Energy Payment, item (2).
DAEREV $_{q, p, r}$	$	*Day-Ahead Energy Revenue per QSE by Settlement Point per unit*—Therevenue received in the DAM for RMR Unit *r* at Resource Node *p* represented by QSE *q*, based on the DAM Settlement Point Price, for the hour.
DASPP $_{p}$	$/MWh	*Day-Ahead Settlement Point Price by Settlement Point*—The DAM Settlement Point Price at Resource Node *p* for the hour.
DAESR $_{q, p, r}$	MW	*Day-Ahead Energy Sale from Resource per QSE by Settlement Point per unit*—Theamount of energy cleared through Three-Part Supply Offers in the DAM and/or DAM Energy-Only Offer Curves for RMR Unit *r* at Resource Node *p* represented by QSE *q* for the hour.
DAEPAMTQSETOT $_{q}$	$	*Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total charge to QSE *q* for cleared DAM Energy Bids for the hour. See Section 4.6.2.2, Day-Ahead Energy Charge, item (2).
DARTOBLAMTQSETOT $_{q}$	$	*Day-Ahead Real-Time Obligation Amount QSE Total per QSE* —The total charge or payment to QSE *q* for PTP Obligation Bids cleared in the DAM for the hour. See Section 4.6.3, Settlement for PTP Obligations Bought in DAM, item (2).
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	An RMR Unit.

7.9.3.2 Credit to CRR Balancing Account

If the Day-Ahead Congestion Rent is greater than the total payment to all CRR Owners for the CRRs settled in the DAM for any Operating Hour, a credit is put into the CRR Balancing Account for that Operating Hour. The credit to the CRR Balancing Account for a given Operating Hour is calculated as follows:

CRRBACR = Max (0, (DACONGRENT + DACRRCRTOT + DACRRCHTOT))

Where:

$$\text{DACRRCRTOT} = \text{DAOBLCRTOT} + \text{DAOBLRCRTOT} + \text{DAOPTAMTTOT} + \text{DAOPTRAMTTOT} + \text{DAFGRAMTTOT}$$

$$\text{DACRRCHTOT} = \text{DAOBLCHTOT} + \text{DAOBLRCHTOT}$$

$$\text{DAOBLCRTOT} = \sum_{o} \text{DAOBLCROTOT}_{o}$$

$$\text{DAOBLCHTOT} = \sum_{o} \text{DAOBLCHOTOT}_{o}$$

$$\text{DAOBLRCRTOT} = \sum_{o} \text{DAOBLRCROTOT}_{o}$$

$$\text{DAOBLRCHTOT} = \sum_{o} \text{DAOBLRCHOTOT}_{o}$$

$$\text{DAOPTAMTTOT} = \sum_{o} \text{DAOPTAMTOTOT}_{o}$$

$$\text{DAOPTRAMTTOT} = \sum_{o} \text{DAOPTRAMTOTOT}_{o}$$

$$\text{DAFGRAMTTOT} = \sum_{o} \text{DAFGRAMTOTOT}_{o}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
CRRBACR	$	*CRR Balancing Account Credit*—The credit to the CRR Balancing Account for the hour.
DACONGRENT	$	*Day-Ahead Congestion Rent*—The Congestion Rent collected in the DAM for the hour. See 7.9.3.1.
DACRRCRTOT	$	*Day-Ahead CRR Credit Total*—The total payment to all CRR Owners of all CRRs settled in the DAM for the hour.
DACRRCHTOT	$	*Day-Ahead CRR Charge Total*—The total charge to all CRR Owners of all CRRs settled in the DAM for the hour.
DAOBLCRTOT	$	*Day-Ahead Obligation Credit Total*—The total payment of all PTP Obligations settled in the DAM, for the hour.
DAOBLCHTOT	$	*Day-Ahead Obligation Charge Total*—The total charge of all PTP Obligations settled in the DAM, for the hour.
DAOBLRCRTOT	$	*Day-Ahead Obligation with Refund Credit Total*—The total payment of all PTP Obligations with Refund settled in the DAM, for the hour.
DAOBLRCHTOT	$	*Day-Ahead Obligation with Refund Charge Total*—The total charge of all PTP Obligations with Refund settled in the DAM, for the hour.
DAOPTAMTTOT	$	*Day-Ahead Option Amount Total*—The total payment of all PTP Options settled in the DAM, for the hour.
DAOPTRAMTTOT	$	*Day-Ahead Option with Refund Amount Total*—The total payment of all PTP Options with Refund settled in the DAM, for the hour.
DAFGRAMTTOT	$	*Day-Ahead FGR Amount Total*—The total payment of all FGRs settled in the DAM, for the hour.

Variable	Unit	Definition
$DAOBLCROTOT_o$	$	*Day-Ahead Obligation Credit Owner Total per owner*—The total payment to CRR Owner *o* of PTP Obligations settled in the DAM, for the hour. See Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM.
$DAOBLCHOTOT_o$	$	*Day-Ahead Obligation Charge Owner Total per owner*—The total charge to CRR Owner *o* of PTP Obligations settled in the DAM, for the hour. See Section 7.9.1.1.
$DAOBLRCROTOT_o$	$	*Day-Ahead Obligation with Refund Credit Owner Total per owner*—The total payment to the CRR Owner *o* of PTP Obligations with Refund settled in the DAM, for the hour. See Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM.
$DAOBLRCHOTOT_o$	$	*Day-Ahead Obligation with Refund Charge Owner Total per owner*—The total charge to CRR Owner *o* of PTP Obligations with Refund settled in the DAM, for the hour. See Section 7.9.1.5.
$DAOPTAMTOTOT_o$	$	*Day-Ahead Option Amount Owner Total per owner*—The total payment to the CRR Owner *o* of PTP Options settled in the DAM, for the hour. See Section 7.9.1.2, Payments for PTP Options Settled in DAM.
$DAOPTRAMTOTOT_o$	$	*Day-Ahead Option with Refund Amount Owner Total per owner*—The total payment to the CRR Owner *o* of PTP Options with Refund settled in the DAM, for the hour. See Section 7.9.1.6, Payments for PTP Options with Refund Settled in DAM.
$DAFGRAMTOTOT_o$	$	*Day-Ahead FGR Amount Owner Total per owner*—The total payment to the CRR Owner *o* of FGRs settled in the DAM, for the hour. See Section 7.9.1.4, Payments for FGRs Settled in DAM.
o	none	A CRR Owner.

7.9.3.3 Shortfall Charges to CRR Owners

(1) For each Operating Hour, if the Day-Ahead Congestion Rent is less than the total payment to all CRR Owners for the CRRs settled in the DAM, a charge will be made to each CRR Owner for any of its CRRs settled in the DAM or Real-Time that have positive settlement prices, except for CRRs bought in the DAM.

(2) The charge to each CRR Owner for its CRRs settled in the DAM for a given Operating Hour is calculated as follows:

$$\mathbf{DACRRSAMT}_{o} = \mathbf{DACRRSAMTTOT * CRRCRRSDA}_{o}$$

Where:

$$DACRRSAMTTOT = (-1) * Min (0, DACONGRENT + DACRRCRTOT + DACRRCHTOT)$$

$$CRRCRRSDA_{o} = (DAOBLCROTOT_{o} + DAOBLRCROTOT_{o} + DAOPTAMTOTOT_{o} + DAOPTRAMTOTOT_{o} +$$

DAFGRAMTOTOT $_o$) / (DACRRCRTOT + RTOPTAMTTOT + RTOPTRAMTTOT)

$$\text{RTOPTAMTTOT} = \sum_{o} \text{RTOPTAMTOTOT}_{o}$$

$$\text{RTOPTRAMTTOT} = \sum_{o} \text{RTOPTRAMTOTOT}_{o}$$

The above variables are defined as follows:

Variable	Unit	Definition
DACRRSAMT $_o$	$	*Day-Ahead CRR Shortfall Amount per owner*—The shortfall charge to CRR Owner *o* for its CRRs settled in the DAM, for the hour.
DACRRSAMTTOT	$	*Day-Ahead CRR Shortfall Amount Total*—The shortfall charge to all CRR Owners for their CRRs settled in the DAM and the RTM, for the hour.
DACONGRENT	$	*Day-Ahead Congestion Rent*—The Congestion Rent collected in the DAM for the hour. See 7.9.3.1.
DACRRCRTOT	$	*Day-Ahead CRR Credit Total*—The total payment to all CRR Owners of all the CRRs settled in the DAM, for the hour. See 7.9.3.2.
DACRRCHTOT	$	*Day-Ahead CRR Charge Total*—The total charge to all CRR Owners of all the CRRs settled in the DAM, for the hour. See 7.9.3.2.
CRRCRRSDA $_o$	none	*CRR Credit Ratio Share Day-Ahead per owner*—The ratio of the total payments to CRR Owner *o* of its CRRs settled in the DAM to the total payments to all CRR Owners of all CRRS, for the hour.
DAOBLCROTOT $_o$	$	*Day-Ahead Obligation Credit Owner Total per owner*—The total payment to CRR Owner *o* of PTP Obligations settled in the DAM, for the hour. See Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM.
DAOBLRCROTOT $_o$	$	*Day-Ahead Obligation with Refund Credit Owner Total per owner*—The total payment to CRR Owner *o* of PTP Obligations with Refund settled in the DAM, for the hour. See Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM.
DAOPTAMTOTOT $_o$	$	*Day-Ahead Option Amount Owner Total per owner*—The total payment to CRR Owner *o* of PTP Options settled in the DAM, for the hour. See Section 7.9.1.2, Payments PTP Options Settled in DAM.
DAOPTRAMTOTOT $_o$	$	*Day-Ahead Option with Refund Amount Owner Total per owner*—The total payment to CRR Owner *o* of PTP Options with Refund settled in the DAM, for the hour. See Section 7.9.1.6, Payments for PTP Options with Refund Settled in DAM
DAFGRAMTOTOT $_o$	$	*Day-Ahead FGR Amount Owner Total per owner*—The total payment to CRR Owner *o* of FGRs settled in the DAM, for the hour. See Section 7.9.1.4, Payments for FGRs Settled in DAM.
RTOPTAMTTOT	$	*Real-Time Option Amount Total*—The total of payments to all CRR Owners of all PTP Options settled in Real-Time for the hour.
RTOPTRAMTTOT	$	*Real-Time Option with Refund Amount Total*—The total of payments to all CRR Owners of all PTP Options with Refund settled in Real-Time for the hour.
RTOPTAMTOTOT $_o$	$	*Real-Time Option Amount Owner Total per owner*—The total payment to CRR Owner *o* of all its PTP Options settled in Real-Time for the hour. See Section 7.9.2.2, Payments for PTP Options Settled in Real-Time.
RTOPTRAMTOTOT $_o$	$	*Real-Time Option with Refund Amount Owner Total per owner*—The total

Variable	Unit	Definition
		payment to CRR Owner *o* of all its PTP Options with Refund settled in Real-Time for the hour. See Section 7.9.2.3, Payments for NOIE PTP Options with Refund Settled in Real-Time.
o	none	A CRR Owner.

(3) The charge to each CRR Owner for its CRRs settled in Real-Time for a given Operating Hour is calculated as follows:

$$\mathbf{RTCRRSAMT}_{o} = \mathbf{DACRRSAMTTOT * CRRCRRSRT}_{o}$$

Where:

$$\text{CRRCRRSRT}_{o} = (\text{RTOPTAMTOTOT}_{o} + \text{RTOPTRAMTOTOT}_{o}) / (\text{DACRRCRTOT} + \text{RTOPTAMTTOT} + \text{RTOPTRAMTTOT})$$

$$\text{RTOPTAMTTOT} = \sum_{o} \text{RTOPTAMTOTOT}_{o}$$

$$\text{RTOPTRAMTTOT} = \sum_{o} \text{RTOPTRAMTOTOT}_{o}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTCRRSAMT $_{o}$	$	*Real-Time CRR Shortfall Amount per owner*—The shortfall charge to CRR Owner *o* for its CRRs settled in Real-Time, due to deration, for the hour.
DACRRSAMTTOT	$	*Day-Ahead CRR Shortfall Amount Total*—The shortfall charge to all CRR Owners for their CRRs settled in the DAM and the RTM, due to deration, for the hour.
CRRCRRSRT $_{o}$	none	*CRR Credit Ratio Share Real-Time per owner*—The ratio of the total payments to CRR Owner *o* of its CRRs settled in Real-Time to the total payments to all CRR Owners of all CRRS, for the hour.
RTOPTAMTTOT	$	*Real-Time Option Amount Total*—The total of payments to all CRR Owners of all PTP Options settled in Real-Time for the hour.
RTOPTRAMTTOT	$	*Real-Time Option with Refund Amount Total*—The total of payments to all CRR Owners of all PTP Options with Refund settled in Real-Time for the hour.
RTOPTAMTOTOT $_{o}$	$	*Real-Time Option Amount Owner Total per owner*—The total payment to CRR Owner *o* of all its PTP Options settled in Real-Time for the hour. See Section 7.9.2.2, Payments for PTP Options Settled in Real-Time.
RTOPTRAMTOTOT $_{o}$	$	*Real-Time Option with Refund Amount Owner Total per owner*—The total payment to CRR Owner *o* of all its PTP Options with Refund settled in Real-Time for the hour. See Section 7.9.2.3, Payments for NOIE PTP Options with Refund Settled in Real-Time.
o	none	A CRR Owner.

(4) An additional charge to each CRR Owner for its CRRs settled in Day-Ahead for a given Operating Hour is calculated as follows:

$$\mathbf{DACRRSRTAMT}_{o} = \mathbf{RTCRRSAMTTOT * DACRRSR}_{o}$$

Where:

$$\text{RTCRRSAMTTOT} = \sum_{o} \text{RTCRRSAMT}_{o}$$

$$\text{DACRRSR}_{o} = (\text{DAOBLCROTOT}_{o} + \text{DAOBLRCROTOT}_{o} + \text{DAOPTAMTOTOT}_{o} + \text{DAOPTRAMTOTOT}_{o} + \text{DAFGRAMTOTOT}_{o}) / \text{DACRRCRTOT}$$

The above variables are defined as follows:

Variable	**Unit**	**Definition**
DACRRSRTAMT_{o}	$	*Day-Ahead CRR Short Ratio Real-Time Amount per owner*—The shortfall charge to CRR Owner *o* for their CRRs settled in the DAM due to Real-Time CRR Shortfall Amount for the hour.
RTCRRSAMTTOT	$	*Real-Time CRR Shortfall Amount Total*—The total Real-Time shortfall charge for CRRs settled in Real-Time for the hour.
RTCRRSAMT_{o}	$	*Real-Time CRR Shortfall Amount per owner*—The shortfall charge to CRR Owner *o* for its CRRs settled in Real-Time for the hour.
DACRRSR_{o}	none	*Day-Ahead CRR Short Ratio per owner*—The ratio of the total payments to CRR Owner *o* of its CRRs settled in Day-Ahead to the total payments to all CRR Owners of all CRRs settled in Day-Ahead, for the hour.
o	none	A CRR Owner.

7.9.3.4 Monthly Refunds to Short-Paid CRR Owners

(1) On a monthly basis, a refund may be paid to the CRR Owners that have a shortfall charge for any Operating Hour in a month. The refund to each CRR Owner for a given month is calculated as follows:

$$\mathbf{CRRRAMT}_{o} = \mathbf{(-1) * Min\ (CRRBACRTOT, CRRSAMTTOT) * CRRSAMTRS}_{o}$$

Where:

$$\text{CRRBACRTOT} = \sum_{h} \text{CRRBACR}_{h}$$

If (CRRSAMTTOT = 0)

$$\text{CRRSAMTRS}_{o} = 0$$

Otherwise

$$\text{CRRSAMTRS}_{o} = \text{CRRSAMTOTOT}_{o} / \text{CRRSAMTTOT}$$

$$\text{CRRSAMTTOT} = \sum_{o} \text{CRRSAMTOTOT}_{o}$$

$$\text{CRRSAMTOTOT}_{o} = \sum_{h} (\text{DACRRSAMT}_{o,h} + \text{RTCRRSAMT}_{o,h})$$

The above variables are defined as follows:

Variable	Unit	Definition
CRRRAMT $_{o}$	$	*CRR Refund Amount per owner*—The refund to the short-paid CRR Owner *o* for the month.
CRRBACRTOT	$	*CRR Balancing Account Credit Total*—The total of credits accumulated in the CRR Balancing Account for all Operating Hours in the month.
CRRSAMTTOT	$	*CRR Shortfall Amount Total*—The total of shortfall charges to all CRR Owners for all Operating Hours in the month.
CRRSAMTRS $_{o}$	none	*CRR Shortfall Amount Ratio Share per owner*—The ratio of the CRR Owner *o*'s total shortfall-charge to the total of all the CRR Owners' shortfall charges, for the month.
CRRSAMTOTOT $_{o}$	$	*CRR Shortfall Amount Owner Total per owner*—The total of shortfall charges to CRR Owner *o* for all Operating Hours in the month.
DACRRSAMT $_{o, h}$	$	*Day-Ahead CRR Shortfall Amount per owner per hour*—The shortfall charge to CRR Owner *o* for its CRRs settled in the DAM for the hour *h*.
RTCRRSAMT $_{o, h}$	$	*Real-Time CRR Shortfall Amount per owner per hour*—The shortfall charge to CRR Owner *o* for its CRRs settled in Real-Time for the hour *h*.
CRRBACR $_{h}$	$	*CRR Balancing Account Credit per hour*—The credit to the CRR Balancing Account for the hour *h*.
h	none	An Operating Hour in the month.
o	none	A CRR Owner.

(2) Additional Monthly Refunds to Short-Paid Day-Ahead CRR Owners

On a monthly basis, additional refunds may be paid to the CRR Owners due to the charges that are caused by Real-Time CRR shortfall, as described in paragraph (4) of Section 7.9.3.3, Shortfall Charges to CRR Owners. The refund to each Day-Ahead CRR Owner for a given month is calculated as follows:

$$\mathbf{DACRRRAMT}_{\boldsymbol{o}} = \mathbf{(-1) * RTCRRSAMTMTOT * DACRRSAMTRS}_{\boldsymbol{o}}$$

Where:

$$\text{RTCRRSAMTMTOT} = \sum_{h} \text{RTCRRSAMTTOT}_{h}$$

If (RTCRRSAMTMTOT = 0)

$$\text{DACRRSAMTRS}_{o} = 0$$

Otherwise

$$\text{DACRRSAMTRS}_{o} = \text{DACRRSRTAMTOTOT}_{o} / \text{DACRRSRTAMTTOT}$$

$$\text{DACRRSRTAMTTOT} = \sum_{o} \text{DACRRSRTAMTOTOT}_{o}$$

$$\text{DACRRSRTAMTOTOT}_{o} = \sum_{h} (\text{DACRRSRTAMT}_{o, h})$$

The above variables are defined as follows:

Variable	Unit	Definition
$DACRRRAMT_{o}$	$	*Day-Ahead CRR Refund Amount per owner*—The additional refund to the Day-Ahead CRR Owner *o* due to Real-Time shortfall charges for the month.
RTCRRSAMTMTOT	$	*Real-Time CRR Shortfall Amount Monthly Total*—The total Real-Time shortfall charge for CRRs settled in Real-Time for the month.
$RTCRRSAMTTOT_{h}$	$	*Real-Time CRR Shortfall Amount Total*—The total Real-Time shortfall charge for CRRs settled in Real-Time for the hour.
$DACRRSAMTRS_{o}$	none	*Day-Ahead CRR Short Amount Ratio Share per owner*—The ratio of the Day-Ahead CRR Owner *o*'s additional total shortfall-charge to the total of all the Day-Ahead CRR Owners' additional shortfall charges, for the month.
$DACRRSRTAMTOTOT_{o}$	$	*Day-Ahead CRR Short Ratio Real-Time Amount Total per owner*—The total of shortfall charges to CRR Owners for all Operating Hours in the Month.
$DACRRSRTAMT_{o,h}$	$	*Day-Ahead CRR Short Ratio Real-Time Amount per owner*—The shortfall charge to CRR Owner *o* for their CRRs settled in the DAM due to Real-Time CRR Shortfall Amount for the hour.
h	none	An Operating Hour in the month.
o	none	A CRR Owner.

7.9.3.5 CRR Balancing Account Closure

(1) After calculation of refunds described in Section 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners, any surplus that remains in the CRR Balancing Account, is paid to the QSEs representing Load Serving Entities (LSEs) based on a monthly Load Ratio Share. The monthly Load Ratio Share is the 15-minute Load Ratio Share calculated for the peak-load Settlement Interval during the month.

(2) The credit to each QSE representing LSEs for a given month is calculated as follows:

$$\mathbf{LACRRAMT}_{q} = \mathbf{(-1) * (CRRBACRTOT + CRRRAMTTOT) * MLRS}_{q}$$

Where:

$$\text{CRRRAMTTOT} = \sum_{o} \text{CRRRAMT}_{o}$$

The above variables are defined as follows:

Variable	Unit	Definition
$LACRRAMT_{q}$	$	*Load-Allocated CRR Amount per QSE*—The allocated surplus in the CRR Balancing Account at the end of the month to QSE *q*, based on Load Ratio Share for the month.
CRRBACRTOT	$	*CRR Balancing Account Credit Total*—The total credit accumulated in the CRR Balancing Account during the month. See its calculation in Section 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners.
CRRRAMTTOT	$	*CRR Refund Amount Total*—The total refund to all the previously short-paid CRR Owners at the end of the month.
$CRRRAMT_{o}$	$	*CRR Refund Amount per owner*—The refund credited to the CRR Owner *o* at the end of the month.

Variable	Unit	Definition
$MLRS_{q}$	none	*Monthly Load Ratio Share per QSE*—The Load Ratio Share calculated for QSE *q* for the 15-minute monthly peak-load Settlement Interval. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval, for the calculation of LRS for a 15-Minute Settlement Interval.
q	none	A QSE.
o	none	A CRR Owner.

ERCOT Nodal Protocols

Section 8: Performance Monitoring and Compliance

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's] Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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8 PERFORMANCE MONITORING AND COMPLIANCE

This Section describes how the performance of ERCOT, TSPs and QSEs are measured against the requirements of these Protocols. Section 8.1 addresses QSE performance measures, Section 8.2 addresses ERCOT performance measures, Section 8.3 addresses TSP performance measures, and Section 8.4 addresses the consequences of nonperformance. Some of the performance measures are specified in this Section, but in some instances Section 8 requires ERCOT to develop other performance measures that must be approved by the Technical Advisory Committee (TAC) and included in the Operating Guides before implementation. Summaries of the performance of each TSP and QSE and of ERCOT are to be made available to all Market Participants.

8.1 QSE/Resource Performance Monitoring and Compliance

(1) ERCOT shall develop a Technical Advisory Committee (TAC)-approved Qualified Scheduling Entity (QSE)/Resource monitoring Program to be included in the Operating Guides. Nothing in this Section changes the process for amending the Operating Guides. The metrics developed by ERCOT and approved by TAC must include the provisions of this Subsection.

(2) Each QSE shall meet, and shall cause each Resource that it represents to meet, performance measures as described in this Subsection and in the Operating Guides. The QSE performance measures assess the Real-Time delivery of Ancillary Service by the QSE. Resource performance measures assess the capability of a Resource to meet the requirements of these Protocols and the Operating Guides.

(3) ERCOT shall monitor the following categories of performance and compliance;

(a) Net dependable real power capability testing, for QSEs and Resources;

(b) Reactive testing, for Generation Resources;

(c) Real-Time data, for QSEs:

(i) Telemetry standards;

(ii) Communications system;

(iii) Operational Data Requirements required under Section 6.5.5.2, Operational Data Requirements.

(d) Written Black Start procedures, for QSEs that represent Generation Resources and for Generation Resources;

(e) Regulation control performance, for QSEs and as applicable, Resource-specific performance (See also Section 8.1.2, QSE Ancillary Service Performance Standards);

(f) Compliance with Dispatch Instructions, for QSEs;

(g) Hydro responsive testing, for QSEs;

(h) Black Start Service requirements, for QSEs and Generation Resources;

(i) Supplying and validating data for generator models, as requested, for Generation Resources;

(j) Twelve-month Outage scheduling, for QSEs and Resources;

(k) Resource-specific Responsive Reserve performance for QSEs and Resources;

(l) Voltage and Reactive support performance for QSEs and Generation Resources;

(m) Generation under-frequency relay coordination as specified in the Operating Guides for Generation Resources;

(n) The backup control for Resource energy deployment due to loss of communication with ERCOT, to be tested by ERCOT randomly at least once a year for QSEs with Resources;

(o) Resource-specific Non-Spinning Reserve (Non-Spin) performance, for QSEs and Resources;

(p) Twenty-four hours per day, seven days per week qualified staffing requirement, as described in the Operating Guides, for QSEs;

(q) Automatic Voltage Regulator (AVR) and Power System Stabilizer (PSS) requirements, for QSEs and Generation Resources;

(r) Staffing plan for a backup control facility or procedures in the event that the primary facility is unusable, for QSEs;

(s) Outage reporting, by QSEs for Resources;

(t) Current Operating Plan metrics, for QSEs;

(u) Testing and performance of governor under the Operating Guides, for Generation Resources;

(v) Other North American Electric Reliability Corporation (NERC) or ERCOT reliability-related assessments, for QSEs and Generation Resources; and,

(w) Day-Ahead Reliability Unit Commitment (DRUC) and Hourly Reliability Unit Commitment (HRUC) commitment performance by QSEs for Generation Resources.

8.1.1 Generating Resource Governor Response Deployment Compliance Monitoring Criteria for Frequency Disturbances

Each Resource not providing Responsive Reserve must meet the following criteria when it is On-Line:

(a) For all frequency deviations exceeding 0.1 Hz, ERCOT shall use recorded two-second scan rate values of real power output for each Resource to evaluate governor response or response to Dispatch Instructions. ERCOT shall use the recorded MW data beginning one minute before the start of the frequency excursion event or Dispatch Instruction until 20 minutes after the start of the frequency excursion event or Dispatch Instruction. Satisfactory performance must be measured by comparing the actual response to the frequency response capability required in the Operating Guides, using methods detailed therein.

(b) ERCOT shall monitor energy that is delivered by a Resource during major frequency disturbances primarily based on the methodology described in the Operating Guides and analyzed using the metric described in the Operating Guides.

8.1.2 QSE Ancillary Service Performance Standards

Each QSE and its Resources that provide Ancillary Service must meet performance measures set out in these Protocols and the Operating Guides. ERCOT shall develop a TAC-approved Ancillary Service monitoring program to evaluate the performance of QSEs and Resources providing Ancillary Services. This program must include monitoring of capacity availability and energy deployments as described below and in Section 6.5.7.5 Ancillary Service Capacity Monitor.

8.1.2.1 Ancillary Service Qualification and Testing

(1) Each QSE and the Resource providing Ancillary Service must meet qualification criteria to operate satisfactorily with ERCOT. ERCOT shall use the Ancillary Service qualification and testing program that is approved by the ERCOT Technical Advisory Committee and included in the Operating Guides. Each QSE for the Resources that it represents may only provide Ancillary Services on those Resources for which it has met the qualification criteria. General capacity testing must be used to verify a Resource's Net Dependable Capability. Net Dependable Capability is the maximum sustained capability of a Resource as demonstrated by performance testing. Each QSE for the Generation Resources that it represents may not submit to ERCOT a High Sustained Limit (HSL) greater than that Resource's Net Dependable Capability without a text description indicating the reason for the increase. Each QSE for the Load Resources that it represents may not provide ERCOT a Maximum Power Consumption (MPC), greater than that Resource's Net Dependable Capability without a text description indicating the reason for the increase. Qualification tests allow the potential provider's portfolio to demonstrate the minimum capabilities necessary to deploy an Ancillary Service.

(2) A Load Resource may be provisionally qualified for a period of 90 days and may be eligible to participate as a Resource. Load Resources that have installed the appropriate equipment with verifiable testing data may be provisionally qualified as providers of Ancillary Service.

(3) A Load Resource may be provisionally qualified for a period of 90 days to participate as a Resource providing Ancillary Service, if the Load Resource is metered with an Interval Data Recorder (IDR) to ERCOT's reasonable satisfaction. A Load Resource providing Ancillary Service in Real-Time, if the Load Resource meets the following requirements:

(a) Electric Service Identifier (ESI ID) registration of Load Resources providing Ancillary Service by the QSE; and

(b) Load Resource telemetry is installed and tested between QSE and ERCOT.

(4) Provisional qualification as described herein may be revoked by ERCOT at any time for any non-compliance with provisional qualification requirements.

8.1.2.2 General Capacity Testing Requirements

(1) Before the start of each season, a QSE shall provide ERCOT a list identifying each Generation Resource that is expected to operate more than 168 hours in a season as a provider of energy or Ancillary Service. ERCOT shall evaluate during each season of expected operation the Net Dependable Capability of each Resource expected to operate more than 168 hours during that season, except for Generation Resources used solely for energy services and whose capacity is less than ten MW. Prior to the beginning of each season, QSEs shall identify the Generation Resources to be tested during the season and the specific week of the test if known. This schedule may be modified by the QSE (including retests) during the season. QSEs not identifying a specific week for a Generation Resource test must test the Resource within the first 168 hours of operation during the season or operate with a Net Dependable Capability equal to the highest integrated hourly MWh output demonstrated during the first 168 hours of operation. QSEs do not have to bring On-Line or shut down Resources solely for the purpose of the seasonal verification. Any Resource for which the QSE desires qualification to provide Ancillary Service shall have its Net Dependable Capability verified prior to providing services using the Generation Resource even if it fits the less-than-168-hour or small-capacity exception. The capability of hydro Resources operating in the synchronous condenser fast response mode to provide hydro Responsive Reserve must be evaluated by season.

(2) Before the start of each season, a QSE shall provide ERCOT a list identifying each Controllable Load Resource that is expected to operate in a season as a provider of Ancillary Service. Prior to the beginning of each season, QSEs shall identify the Controllable Load Resources to be tested during the season and the specific week of the test if known. Any Controllable Load Resource for which the QSE desires qualification to provide Ancillary Services shall have its Net Dependable Capability verified prior to providing Ancillary Services.

(3) ERCOT shall annually verify the telemetry attributes of each qualified Load Resource. In addition, once every two years, any Load Resource qualified to provide Responsive Reserve Service using a high-set under-frequency relay shall test the correct operation of the under-frequency relay or the output from the solid-state switch, whichever applies. However, if a Load Resource's performance has been verified through response to an actual event, the data from the event can be used to meet the annual telemetry verification requirement for that year and the biennial relay-testing requirement.

(4) A specific Load Resource to be used for the first time to provide Regulation, Responsive Reserve or Non-Spin must be tested to ERCOT's reasonable satisfaction (tripped or simulated trip, if required and approved by ERCOT) before its qualification to provide Ancillary Service. The test must take place at a time mutually selected by the QSE representing the Load Resource and ERCOT. ERCOT shall make available its standard test document for simulation of Load interruption required under this Section on the Market Information System (MIS) Public Area. A Load Resource used to provide Responsive Reserve must be qualified for correct relay operation by its host Transmission Service Provider (TSP) and Distribution Service Provider (DSP), if applicable.

(5) Any changes to a Load Resource including changes to its capability to provide Ancillary Service requires updates by the Load Resource to the registration information detailing the change. For Non-Opt-In Entities (NOIEs) representing specific Load Resources that are located behind the NOIE Settlement Metering points, the NOIE shall provide an alternative unique descriptor of the qualified Load Resource for ERCOT's records.

(6) Generation Resources and Load Resources must be evaluated at least annually by ERCOT for the following:

(a) Correct operation of all required telemetry as described in these Protocols including the telemetry of the breakers and switches controlling the Resource;

(b) Correct mapping of QSE-provided telemetry of Ancillary Service energy to the appropriate energy Settlement Meter; and

(c) Data rate update requirements and any other required telemetry attributes.

(7) Generation Resources and Load Resources must meet the requirements specified in the Operating Guides for proper response to system frequency. ERCOT may reduce the amount a Resource may contribute toward Ancillary Service if it determines unsatisfactory performance of the Resource as defined in these Protocols and the Operating Guides.

(8) Qualification of a Resource, including a Load Resource, remains valid for that Resource in the event of a change of QSE for the Resource, provided that the new QSE demonstrates to ERCOT's reasonable satisfaction that the new QSE has adequate communications and control capability for the Resource.

8.1.2.2.1 Ancillary Service Technical Requirements and Qualification Criteria and Test Methods

(1) A QSE and the Resource that it represents that have been qualified and tested may provide Ancillary Service. ERCOT shall develop and operate its qualification and testing program to meet the requirements of this Section for each Ancillary Service.

(2) A QSE must be qualified and tested to provide Ancillary Service prior to initial operation and every five years thereafter. ERCOT may conduct two unannounced, unscheduled qualification tests after presenting to the QSE supporting information that a Generation Resource or Load Resource may not be able to meet its stated Net Dependable Capability during any year.

(3) A QSE may request a test for re-qualification at any time, but no later than the expiration of its Resource's current Ancillary Service qualification, and no more frequently than once every twelve months. At the time of a request by a QSE for re-qualification of its Resources, ERCOT may approve the re-qualification based on the Ancillary Service performance metrics using the following criteria:

(a) For the QSE and for the Resources that it represents that are qualified for Regulation Service, the performance scores in Section 8.1.2.4.1, Regulation Service Energy Deployment Criteria, were passing for five out of the previous six months.

(b) For each Resource qualified to provide RRS, the RRS criteria in Section 8.1.2.4.2, Responsive Reserve Service Energy Deployment Criteria, were passing for five out of the previous six deployment measurements.

(c) For each resource qualified to provide Non-Spin, the Non-Spin monitoring criteria in Section 8.1.2.4.3, Non-Spinning Reserve Energy Deployed under Dispatch Instruction Criteria, were passing for five out of the previous six deployment measurements without retest.

(4) If the QSE passes the criteria, the QSE's Resource will be exempt from re-qualification testing for five years from the date of the exemption request. ERCOT shall provide monthly performance updates to the QSE for the above performance measures.

(5) ERCOT may grant a "Provisional Qualification," for a period not to exceed 90 days, to a Load Resource that has performed an Ancillary Service qualification test (or tests) in good faith but failed to qualify due to problems that, in the sole discretion of ERCOT, are determined to be non-critical for the purpose of providing one or more Ancillary Service. Notwithstanding the failure of a Load Resource with Provisional Qualification to meet the applicable Ancillary Service criteria, such Load Resource may provide such Ancillary Service to the extent permitted by the terms of the Provisional Qualification.

8.1.2.2.2 Regulation Service

(1) A QSE control system must be capable of receiving digital control signals from ERCOT's control system, and of directing its Resources to respond to the control signals, in an upward and downward direction to balance Real-Time Demand and Resources, consistent with established NERC and ERCOT operating criteria. A QSE providing Regulation Up Service (Reg-Up) or Regulation Down Service (Reg-Down) shall provide communications equipment to receive telemetered control deployments of power from ERCOT.

(2) A QSE shall demonstrate to ERCOT that they have the ability to switch control to constant frequency operation as specified in the Operating Guides using telemetry at the QSE's control center. ERCOT-authorized operations of the QSE's regulation control system on constant frequency will be considered a Dispatch Instruction.

(3) A QSE providing Reg-Up or Reg-Down shall provide ERCOT with the data requirements of Section 6.5.5.2, Operational Data Requirements, and a feedback signal meeting the requirements of ERCOT. Resources providing Reg-Up or Reg-Down must be capable of delivering the full amount of regulating capacity offered to ERCOT within five minutes.

(4) Each Resource providing Reg-Up or Reg-Down must meet technical requirements specified in these Protocols. Each Generation Resource providing Reg-Up or Reg-Down must have their governors in service.

(5) A Resource providing Reg-Up and Reg-Down must be able to respond in the Operating Hour for which it has been selected to provide the Ancillary Service.

(6) A Reg-Up and Reg-Down qualification test for each Resource is conducted during a continuous 60-minute period agreed on in advance by the QSE and ERCOT. QSEs may qualify a Resource to provide Reg-Up or Reg-Down, or both, in separate testing. ERCOT shall administer the following test requirements:

(a) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice communication circuits to validate the voice circuits.

(b) For the 60-minute duration of the test, when market and reliability conditions allow, the ERCOT Control Area Operator shall send a random sequence of raise, hold, and lower control signals to the QSE for a specific Resource. To facilitate accurate measurements, each signal (raise, lower, or hold) must remain unchanged for at least two minutes. The control signals may not request Resource performance beyond the High Ancillary Service Limit (HASL), Low Ancillary Service Limit (LASL), and ramp rate limit agreed on prior to the test. During the test, a ten-minute period is used to test the Resource's ability to achieve the entire amount of Reg-Up requested for qualification during the period. A ten-minute period is used to test the QSE's ability to achieve the entire amount of Reg-Down requested for qualification during the period.

(c) ERCOT shall measure and record the average real power output for each minute of the Resource(s) being tested represented by the QSE. The correlation coefficient between the expected average power from one minute to the next (limited to no more than the initial value + [request "1/2 " stated ramp rate]), and the actual measured real power output of the Resource(s) during those minutes must be statistically significant to two positive standard deviations in order to pass the test.

(d) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing Regulation Service and shall provide a copy of the certificate to the QSE and the Resource.

8.1.2.2.3 Responsive Reserve Service

(1) RRS may be provided by:

(a) Unloaded Generation Resources that are On-Line;

(b) Load Resources controlled by high-set under-frequency relays;

(c) Hydro Responsive Reserves;

(d) Direct Current Tie (DC Tie) response that stops frequency decay; or,

(e) Controllable Load Resources.

(2) The amount of RRS provided by individual Generation Resources and Controllable Load Resources is specified in the Operating Guides. Each Resource providing RRS must be On-Line and capable of ramping the Resource's Ancillary Service Resources Responsibility for RRS within ten minutes of the notice to deploy RRS, must be immediately responsive to system frequency, and must be able to maintain the scheduled level of deployment for the period of service commitment. The amount of RRS on a Generation Resource may be further limited by requirements of the Operating Guides.

(3) A QSE's Load Resource must be loaded and capable of unloading the scheduled amount of RRS within ten minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays with settings as specified by the Operating Guides.

(4) Any QSE providing RRS shall provide communications equipment to receive ERCOT telemetered control deployments of RRS.

(5) Generation Resources providing RRS shall have their governors in service.

(6) Load Resources on high-set under-frequency relays providing RRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay.

(7) Each QSE shall ensure that each Resource is able to meet the Resource's obligations to provide the Ancillary Service Resource Responsibility. Each Generation Resource and Load Resource providing RRS must meet additional technical requirements specified in this Section.

(8) A qualification test for each Resource to provide RRS is conducted during a continuous eight-hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits. ERCOT shall administer the following test requirements:

(a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE it is to provide an amount of RRS from its Resource to be qualified equal to the amount that the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) For Generation Resources desiring qualification to provide Responsive Reserve, ERCOT shall send a signal to the Resource's QSE to deploy Responsive Reserve, indicating the MW amount. ERCOT shall monitor the QSEs telemetry of the Resource's Ancillary Service Schedule for an update within fifteen seconds. ERCOT shall measure the test Resource's response as described under Section 8.1.2.4.2. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource's qualification to provide Responsive Reserve.

(c) For Controllable Load Resources desiring qualification to provide Responsive Reserve, ERCOT shall send a signal to the Resource's QSE to deploy Responsive Reserve, indicating the MW amount. ERCOT shall measure the test Resource's response as described under Section 8.1.2.4.2. ERCOT shall evaluate the response of the Controllable Load Resource given the current operating conditions of the system and determine the Controllable Load Resource's qualification to provide Responsive Reserve.

(d) For Load Resources, excluding Controllable Load Resources, desiring qualification to provide Responsive Reserve, ERCOT shall deploy Responsive Reserve, indicating the MW amount. ERCOT shall measure the test Resource's response as described under Section 8.1.2.4.2.

(e) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing RRS and shall provide a copy of the certificate to the QSE and the Resource Entity.

8.1.2.2.4 Non-Spinning Reserve

(1) Each Resource providing Non-Spin must be capable of being synchronized and ramped to its Ancillary Service Schedule for Non-Spin within 30 minutes. Non-Spin may be provided from Generation Resource capacity that can ramp within 30 minutes or Load

Resources capable of unloading within 30 minutes. Non-Spin may only be provided from capacity that is not fulfilling any other energy or capacity commitment.

(2) A Load Resource providing Non-Spin must provide a telemetered output signal, including breaker status.

(3) Each Generation Resource and Load Resource providing Non-Spin must meet additional technical requirements specified in this Section.

(4) QSEs using a Load Resource to provide Non-Spin must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resource to provide Non-Spin.

(5) Each QSE shall ensure that each Resource is able to meet the Resource's obligations to provide the Ancillary Service Resource Responsibility. Each Generation Resource and Load Resource providing Non-Spin must meet additional technical requirements specified in this Section.

(6) For any Resource requesting qualification for Non-Spin, a qualification test for each Resource to provide Non-Spin is conducted during a continuous eight hour period agreed to by the QSE and ERCOT. ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits. ERCOT shall administer the following test requirements.

(a) At any time during the window (selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE), ERCOT shall notify the QSE by using the Messaging System and requesting that the QSE provide an amount of Non-Spin from each Resource equal to the amount for which the QSE is requesting qualification. The QSE shall acknowledge the start of the test.

(b) For Generation Resources: during the test window, ERCOT shall send a message to the QSE representing a Generation Resources to deploy Non-Spin. ERCOT shall monitor the adjustment of the Generation Resource's Non-Spin Ancillary Service Schedule within five minutes for Resources On-Line. ERCOT shall measure the test Resource's response as described under Section 8.1.2.4.3. ERCOT shall evaluate the response of the Generation Resource given the current operating conditions of the system and determine the Resource's qualification to provide Non-Spin Reserve.

(c) For Load Resources, including Controllable Load Resources, ERCOT shall send an instruction to deploy Non-Spin. ERCOT shall measure the test Resource's response as described under Section 8.1.2.4.3:

(d) On successful demonstration of all test criteria, ERCOT shall qualify that the Resource is capable of providing Non-Spin and shall provide a copy of the certificate to the QSE and the Resource Entity.

8.1.2.2.5 Reactive Supply from Generation Resources providing Voltage Support Service (VSS)

(1) The Generation Entity must verify and maintain its stated Reactive Power capability for each of its Generation Resources providing VSS, as required by the Operating Guides. Generation Resources providing VSS reactive capability limits shall be specified considering nominal substation voltage.

(2) The Generation Resource Entity shall conduct reactive capacity qualification tests to verify the maximum leading and lagging reactive capability of all Generation Resources required to provide VSS. Reactive capability tests are performed on initial qualification and at a minimum of once every two years. ERCOT may require additional testing if it has information indicating that current data is inaccurate. The Generation Resource Entity is not obligated to place Generation Resources On-Line solely for the purposes of testing. The reactive capability tests must be conducted at a time agreed on in advance by the Generation Resource Entity, its QSE, the applicable Transmission and/or Distribution Service Provider (TDSP), and ERCOT.

(3) Maximum lagging power factor reactive operating limit must be demonstrated during peak Load Season, at or above 95% of the most currently tested Net Dependable Capability, insofar as system voltage conditions and other factors will allow. The Generation Resource providing VSS is required to maintain this level of Reactive Power for 15 minutes.

(4) Maximum leading power factor reactive operating limit must be demonstrated during light Load conditions, with the Generation Resource operating at a typical output for that condition, or the normal expected output level for solid fuel Generation Resources during light Load conditions, insofar as system voltage conditions and other factors will allow. The Resource is required to maintain this level of Reactive Power for 15 minutes.

(5) The Generation Resource Entity shall perform the Resource AVR tests and shall supply AVR data as specified in the Operating Guides. The AVR tests must be performed on initial qualification and periodically at an ERCOT-set interval no more often than once every five years. The AVR tests must be conducted at a time agreed on in advance by the Generation Resource Entity, its QSE, the applicable TSP and ERCOT.

8.1.2.2.6 System Black Start Capability

(1) A Resource is qualified to be a Black Start Resource if it has met the following requirements:

(a) Verified control communication path performance;

(b) Verified primary and alternate voice circuits for receipt of instructions;

(c) Passed the “Basic Starting Test” as defined below;

(d) Passed the ”Line-Energizing Test” as defined below;

(e) Passed the “Load-Carrying Test” as defined below;

(f) Passed the “Next Start Resource Test” as defined below;

(g) If not starting itself, has an ERCOT-approved firm standby power contract with deliverability under ERCOT blackout circumstances from a non-ERCOT Control Area that can be finalized upon selection as a Black Start Resource;

(h) If not starting itself, has an ERCOT approved agreement with the necessary TDSPs for access to another power pool, for coordination of switching during a black-start event, for coordination of maintenance through the ERCOT Outage scheduler for all non-redundant transmission startup feeds; and

(i) If dependent upon non-ERCOT transmission resources, agreements providing this Transmission Service have been provided in the proposal.

(2) On successful demonstration of system Black Start Service capability, ERCOT shall certify that the Black Start Resource is capable of providing system Black Start Service capacity and shall provide a copy of the certificate to the Black Start Resource. Qualification shall be valid for the time frames set forth below. Except under extenuating circumstances, as reasonably determined by ERCOT, all qualification testing for the next year of Black Start Service must be completed by December 1 of each year. ERCOT shall revoke the Qualification of a Black Start Resource and reduce the Black Start Resources’ Hourly Standby Fee (if under an existing Black Start Agreement) to zero during the time of disqualification if the Black Start Resource fails to perform successfully during a test described herein, until the Black Start Resource is successfully retested. ERCOT may limit the number of retests allowed. Retesting is required only for the aspect of system Black Start Service capability for which the Black Start Resource failed. If a Black Start Resource under an existing Black Start Agreement does not successfully re-qualify within two months of failing a test described herein, ERCOT shall decertify the Black Start Resource for the remainder of the calendar year as described in Section 7 of the “Standard Form Black Start Agreement.” The following tests are required for Black Start Service qualification:

(a) The “Basic Starting Test” includes the following:

(i) The basic ability of the Black Start Resource to start itself, or start from a normally open interconnection to another provider not inside the ERCOT Interconnection, without support from the ERCOT System;

(ii) Annual testing, either as a stand-alone test or part of the Line Energizing and Load Carrying Tests, and the test is preformed during a one-week period agreed to in advance by the Black Start Resource and ERCOT and must not cause outage to ERCOT Customer Load or the availability of other Resources to the ERCOT market;

(iii) Confirmation of the dates of the test with the Black Start Resource by ERCOT;

(iv) Initiation of the test at a time during a previously agreed test week window not previously disclosed to the Black Start Resource;

(v) Isolation of the Black Start Resource, including all auxiliary Loads, from the ERCOT System, except for the transmission that connects the Resource to a provider not inside the ERCOT Interconnection if the startup power is supplied by a firm standby contract. Black Start Resources starting with the assistance of a provider not inside the ERCOT Interconnection through a firm standby agreement will connect to provider not inside the ERCOT Interconnection, start-up, carry internal Load, disconnect from the provider not inside the ERCOT Interconnection if not supplied through a black-start capable DC Tie, and continue equivalently to what is required of other Black Start Resources;

(vi) The ability of the Black Start Resource to start without assistance from the ERCOT System, except for the transmission that connects the Resource to a provider not inside the ERCOT Interconnection if the startup power is supplied by a firm standby contract;

(vii) The ability of the Black Start Resource to remain stable (in both frequency and voltage) while supplying only its own auxiliary Loads or Loads in the immediate area for at least 30 minutes; and

(viii) The Black Start Resource must have verified that its Volts/Hz relay, over-excitation limiter, and under-excitation limiter are set properly and that no protection devices will trip the Black Start Resource within the required reactive range. The Resource Entity for the Black Start Resource shall provide ERCOT with data to verify these settings.

(ix) Qualification under the Basic Starting Test is valid for one year.

(b) The "Line-Energizing Test" must be conducted at a time agreed on by the Black Start Resource, TSP or DSP, and ERCOT and includes the following:

(i) Energizing transmission with the Black Start Resource when conditions permit as determined by the TSP or DSP but at least once every three years;

(ii) De-energizing sufficient transmission in such manner that when energized by the Black Start Resource it demonstrates the Black Start Resource's ability to energize enough transmission to deliver to the Loads the Resource's output that ERCOT's restoration plan requires the Black Start Resource to supply. ERCOT shall be responsible for transmission connections and operations that are compatible with the capabilities of the Black Start Resource;

(iii) Conducting a Basic Starting Test;

(iv) Energizing transmission with the Black Start Resource of the previously de-energized transmission, while monitoring frequency and voltages at both ends of the line. Alternatively, if ERCOT agrees, the transmission line may be connected to the Black Start Resource before starting, allowing the Resource to energize the line as it comes up to speed; and

(v) Stable operation of the Black Start Resource (in both frequency and voltage) while supplying only its auxiliary Loads or external Loads for at least 30 minutes.

(vi) This test may be performed together with the Basic Starting Test in one 30 minute interval.

(viii) Qualification under the Line-Energizing Test is valid for three years.

(c) The "Load-Carrying Test" shall be tested as conditions permit, but at least once every six years and includes the following:

(i) Stable operation of the Black Start Resource (in both frequency and voltage) while supplying restoration power to Load specified by ERCOT's restoration plan for the Black Start Resource.

(ii) Conducting a Basic Starting Test;

(iii) Conducting a Line-Energizing Test; and

(iv) The TSP or DSP operator for the Black Start Resource shall direct picking up sufficient Load to demonstrate the Black Start Resource's capability to supply the required power identified in ERCOT's restoration plan, while maintaining voltage and frequency for at least 30 minutes.

(v) This test may be performed together with the Basic Starting Test and Line Energizing test in one 30 minute interval.

(vi) Qualification under the Load-Carrying Test is valid for six years.

(d) Next Start Resource Test:

(i) The ability of a Black Start Resource to start up the Next Start unit's largest required motor while continuing to remain stable and control voltage and frequency shall be tested. This test shall be repeated when a new next start unit is selected;

(ii) To pass the test, (a) the potential Black Start Resource must start the next start unit (as determined by ERCOT), or start the next start unit's largest required motor and satisfied the next start unit's minimum startup Load requirements; or (b) the Resource Entity shall demonstrate to the satisfaction of ERCOT staff through simulation studies conducted by the Resource Entity or a qualified third party, that the potential Black Start Resource is capable of starting the next start unit's largest required motor while meeting the next start unit's minimum startup Load requirements. Potential Black Start Service bidders may request next start unit information from ERCOT prior to the selection process to satisfy this requirement. ERCOT shall request this information from the designated next start unit as follows: ERCOT may require any Generation Resource to provide largest motor startup information and unit startup energy requirements as needed to validate Black Start proposals or plans submitted by other Generation Resources. Such data, if requested by ERCOT, shall be provided by the QSE representing the Generation Resource or the Generation Resource Entity to ERCOT within 30 days. Such information shall be considered Protected Information by the requesting Resource Entity when provided to the Resource Entity.

(iii) If a physical test is performed, the test shall commence with a Basic Starting Test, followed by a Line Energizing Test and a Load Carrying Test as a stand-alone test or part of the Next Start Resource Test.

(iv) If a physical test is performed, the Black Start Resource must remain stable (in both voltage and frequency) and controlling voltage for 30 minutes.

(v) If a physical test is performed, this test may be performed together with the Basic Starting Test, Line Energizing Test, and Load Carrying Test in one 30 minute interval.

(vi) Qualification under the Next Start Resource Test is valid until a new next start unit is selected.

(3) ERCOT shall decertify a Black Start Resource for the for that calendar year if the Black Start Resource fails to perform successfully during an actual ERCOT System blackout event and the Black Start Resource has been declared available, as defined in Section 9B(1) of Section 22, Attachment A, Standard Form Black Start Agreement.

8.1.2.3 QSE Ancillary Service Capacity Compliance Monitoring Criteria

ERCOT shall continuously measure the overall performance of each provider of Ancillary Service including estimates of remaining Ancillary Service capacity reserves that can be deployed.

8.1.2.3.1 Regulation Service Capacity Monitoring Criteria

ERCOT shall continuously monitor the capacity of each Resource to provide Reg-Up and Reg-Down. When determining this available capacity, ERCOT shall consider for each Resource with REG status, the actual generation or load, the Ancillary Service Schedule for Reg-Up and Reg-Down, the HSL, the LSL, ramp rates, any other commitments of Ancillary Service capacity, and the amount of Regulation energy currently deployed on the Resource.

8.1.2.3.2 Responsive Reserve Service Capacity Monitoring Criteria

(1) ERCOT shall continuously monitor the capacity of each Resource to provide Responsive Reserve. ERCOT shall consider for each Resource providing Responsive Reserve capacity, the actual generation, or load, the Ancillary Service Schedule for RRS, the HSL, the LSL, ramp rates, any other commitments of Ancillary Service capacity, and any Responsive Reserve energy currently deployed on the Resource.

(2) For Load Resources not deployed by a Dispatch Instruction from ERCOT, the amount of Responsive Reserve capacity provided must be measured as the Load Resource's average Load level in the last five minutes.

(3) A hydro Resource that is capable of providing Hydro Responsive Reserve and that has a status code of ONRR is considered to be providing responsive capability to the extent that it is not using that capacity to provide energy.

(4) For the purpose of monitoring Responsive Reserve performance by individual Generation Resources, the Base Point must be adjusted assuming Responsive Reserve is deployed proportionately or as re-assigned by the QSE to its other Generation Resources. .

(5) For the purposes of monitoring Responsive Reserve performance by individual Controllable Load Resources, the Controllable Load Resource Desired Load must be adjusted assuming Responsive Reserve is deployed proportionately or as re-assigned by the QSE to its other Controllable Load Resources.

8.1.2.3.3 Non-Spinning Reserve Capacity Monitoring Criteria

(1) ERCOT shall continuously monitor the capacity of each Resource to provide Non-Spinning Reserve. ERCOT shall consider for each Resource providing Non-Spin capacity, the actual generation, or load, the Ancillary Service Schedule for Non-Spin, the HSL, the LSL, ramp rates, any other commitments of Ancillary Service capacity, and any Responsive Reserve energy currently deployed on the Resource. ERCOT shall also monitor Non-Spinning Reserve provided on Resources with OFFNS status.

(2) For Load Resources not affected by a Dispatch Instruction from ERCOT, the amount of Non-Spin capacity provided must be measured as the Load Resource's average Load level during the hour.

8.1.2.4 QSE Ancillary Service Energy Deployment Compliance Monitoring Criteria

ERCOT shall measure the performance of each QSE and the Resources that it represents in providing Ancillary Service energy in response to Dispatch Instructions according to the following requirements.

8.1.2.4.1 Regulation Service Energy Deployment Criteria

(1) For each QSE, ERCOT shall calculate one-minute and ten-minute averages of the "Provided Regulation" equal to the sum of (a) and (b) where:

(a) for all of the QSE's Resources in ONREG, ONOSREG or ONRGL status:

(i) the sum of the QSE's actual generation for each Generation Resource or load for each Load Resource; minus

(ii) the sum of the QSE's Base Points for each Resource; minus

(iii) for Generation Resources, the sum of the total expected Governor Response of each Resource; minus

(iv) for Controllable Load Resources, the sum of the total expected frequency response of each Resource; and

(b) for all of the QSE's Resources in ONDSRREG status ("DSRQSE"):

(i) the sum of the DSRQSE's actual generation for each Generation Resource; plus

(ii) the sum of the DSRQSE's awarded DAM Energy Bid quantities; plus

(iii) the sum of the DSRQSE's Energy Trades where the DSRQSE is the buyer and another QSE is the seller; plus

(iv) the sum of the DSRQSE's Energy Trades where the DSRQSE is both the buyer and the seller in the same Energy Trade (*i.e.* creating a static schedule of non-Dynamically Scheduled Resource(s) (DSR(s)) to meet DSR Load); minus

(v) the DSRQSE's actual load; minus

(vi) the sum of the DSRQSE's awarded energy offers in the Day-Ahead Market (DAM); minus

(vii) the sum of the DSRQSE's Energy Trades where the DSRQSE is the seller and another QSE is the buyer; minus

(viii) for Generation Resources, the total expected Governor Response of the Resources.

(2) ERCOT shall also calculate each QSE's participation factor as the ratio for each ten-minute interval of:

(a) the sum of the ten-minute average of the Base Points and Scheduled Power Consumption Snapshots for a QSE's Resources providing Regulation Service plus deployed Ancillary Service; to

(b) the sum of the ten-minute averages for all Base Points and all Scheduled Power Consumption Snapshots for all Resources plus all deployed Ancillary Service.

(3) ERCOT shall limit the deployment of Regulation Service of each QSE for each control cycle equal to 125% of the total amount of Regulation Service in ERCOT divided by the number of control cycles in five minutes. Regulation Service performance must be calculated only for a Resource during intervals for which the Resource shows an ONREG, ONOSREG, or ONRGL status in the Current Operating Plan (COP).

(4) Satisfactory control performance of the QSE providing Regulation Service must be deemed acceptable when:

(a) The one minute averages of the QSE's Provided Regulation meet the criteria in paragraph (5) below over the calendar month, and

(b) The ten minute averages of the QSE's Provided Regulation meet the criteria in paragraph (5) below for 90% of the ten minute periods over the calendar month.

(5) The criterion for the one-minute average is:

$$AVG_{month}\left[\left(\frac{\Pr ovided\ \mathrm{Re}\ gulation_1}{ParticipationFactor}\right)*\left(\frac{\Delta F_1}{(10*Bias_1)*\varepsilon^2{}_1}\right)\right]\leq 1$$

and the criterion for the ten-minute average is:

$$\left|\Pr ovided\ \mathrm{Re}\ gulation_{10}\right|\leq L_{10}*K\sqrt{ParticipationFactor}$$

Where:

Provided Regulation_1 is the one-minute average of Provided Regulation.

Provided Regulation_{10} is the ten-minute average of Provided Regulation.

Bias_1 is the one -minute average of the ERCOT total bias used in the Area Control Error (ACE) calculation.

ΔF_1 is the one -minute average of frequency deviation from schedule.

ε_1 is a constant derived from the targeted frequency bound. It is the targeted Root Mean Square of one minute average frequency error from a schedule based on frequency performance over a given year as established according to NERC Performance Requirements by ERCOT and the appropriate ERCOT Subcommittee as assigned by TAC.

L_{10} is a limit to recognize the desired performance of frequency for ERCOT as established according to NERC performance requirements. L_{10} is defined as (1.65 * E_{10} * $Bias_{10}$) where E_{10} is 0.01315 Hz and $Bias_{10}$ is the ten minute average of the ERCOT total bias used in the ACE calculation for the ERCOT Control Area.

K is a constant that is set to 0.81 to ensure correlation between passing the NERC CPS2 criteria and passing the ten minute control limit and can be adjusted by the appropriate ERCOT Subcommittee as assigned by TAC.

(6) ERCOT shall determine the performance of providers of Ancillary Service under normal operating conditions. ERCOT shall not consider average performance of a QSE any period during which any of the following events has occurred and for which the QSE does not have a passing score:

(a) The 20-minute period in which the QSE has experienced a Forced Outage causing an ERCOT frequency deviation of greater than 0.03 Hz;

(b) Settlement Intervals in which ERCOT has issued Emergency Base Points to the QSE;

(c) The period in which ERCOT issues instructions to the QSE to deploy its Resources at ramp rates in excess of Normal Ramp Rates; and

(d) Certain other periods of abnormal operations as determined by ERCOT in its sole discretion.

8.1.2.4.2 Responsive Reserve Service Energy Deployment Criteria

(1) Each QSE providing Responsive Reserve Service shall so indicate by appropriate entries in the Resource’s Ancillary Service Schedule and the Ancillary Service Resource Responsibility providing that service. When deploying any Responsive Reserve Service to Generation Resources and Controllable Load Resources, the QSE shall control its Resources to operate to the Resource’s Base Point or Scheduled Power Consumption Snapshot at the time of the Dispatch Instruction. ERCOT shall adjust the Generation Resource’s Base Point for any requested Responsive Reserve energy in the next cycle of SCED as specified in Section 6.5.7.6.2.2, Deployment of Responsive Reserve Service. Control performance of a Resource providing Responsive Reserve Service shall be monitored by ERCOT as described below:

(a) For Generation Resources ten minutes following a deployment instruction, the Net Generation of each Resource must not be less than 95%, nor more than 150% of the Resource’s Base Point and be maintained until recalled or the Resource obligation to provide Responsive Reserve expires; and

(b) For Controllable Load Resources ten minutes following a deployment instruction, the Controllable Load Resource response must not be less than 95%, nor more than 150% of the Controllable Load Resource Desired Load and be maintained until recalled or the Resource's obligation to provide Responsive Reserve expires; and

(c) For Load Resources, excluding Controllable Load Resources, the Load Resource response must not be less than 95%, nor more than 150% of the requested MW deployment and be maintained until recalled or the Resource obligation to provide Responsive Reserve expires, and

(d) Within ten minutes following a Responsive Reserve Service recall instruction, a Generation Resource providing Responsive Reserve Service must return to within 95% to 105% of its Base Point.

(e) Within ten minutes following a Responsive Reserve Service recall instruction, a Controllable Load Resource providing Responsive Reserve Service must return to within 95% to 105% of its Scheduled Power Consumption Snapshot, subject to the Resource's Normal Ramp Rates.

(f) A Load Resource providing the Responsive Reserve Service excluding Controllable Load Resources must return to at least 95% of its committed obligation for RRS within three hours following a recall instruction from ERCOT. Each Load Resource that is not a Controllable Load Resource and unable to return to its Ancillary Service Supply Responsibility in three hours may be replaced by the QSE or Load Resource unable to comply using other Generation Resources or other Load Resources not previously committed to provide Responsive Reserve.

(g) During periods when the Load level of a Load Resource, excluding a Controllable Load Resource, has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource's actual Load response from its Baseline. "Baseline" capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

(2) For all frequency deviations exceeding 0.1 Hz, ERCOT shall use the recorded data for each two-second scan rate value of real power output for each Resource providing RRS service. ERCOT shall use the recorded MW data beginning one minute before the start of the frequency excursion event until ten minutes after the start of the frequency excursion event. Satisfactory performance must be measured by comparing the actual response to the frequency response capability required in the Operating Guides.

(3) ERCOT shall monitor the frequency response component of Responsive Reserve Service that is delivered during major frequency disturbances primarily based on a droop calculation for Generators and Controllable Load Resources, a relay response for Loads and Hydro Responsive Reserve. RRS service performance must be analyzed by TAC and a performance metric must be provided in the Operating Guides.

8.1.2.4.3 Non-Spinning Reserve Service Energy Deployment Criteria

(1) ERCOT shall, as part of its Ancillary Service deployment procedure under Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment, include all performance metrics for a Resource receiving a Non-Spin recall instruction from ERCOT.

(2) A Non-Spin Dispatch Instruction from ERCOT must respect the minimum runtime of a Generation Resource. After the recall of a Non-Spin Dispatch Instruction, any Generation Resource previously Off-Line providing Non-Spin is allowed to remain On-Line for 30 minutes following the recall. During that time period, the On-Line Generation Resource is treated as if the Non-Spin is being provided.

(3) Control performance of a Resource providing Non-Spin through a Dispatch Instruction other than a SCED Base Point is acceptable when:

(a) For Generation Resources, 30 minutes following a deployment instruction, the Net Generation of each Resource must not be less than 95%, nor more than 150% of the Resource's Base Point and be maintained until recalled or the Resource Obligation to provide Non-Spin expires.

(b) For Load Resources, including Controllable Load Resources, 30 minutes following a deployment instruction, the Load Resource response must not be less than 95%, nor more than 150% of the requested MW deployment and be maintained until recalled or the Resource obligation to provide Responsive Reserve expires, and

(c) A Load Resource providing Non-Spin must return to at least 95% of its committed obligation for Non-Spin no more than three hours following a recall instruction from ERCOT. Each Load Resource unable to return within three hours to its committed obligation for Non-Spin or pre-deployment capability that was specified in the COP at the time of the deployment, may be replaced by the QSE providing Non-Spin on other Generation Resources or other Load Resources not previously committed.

(d) During periods when the MW load level of a Load Resource has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction will be determined by subtracting the Load Resource's actual Load response from its Baseline. "Baseline" capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of the Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

8.1.2.4.4 Combinations of Reliability Service Energy Deployment Criteria

Each QSE providing combined services shall control each of its Resources to the Resource's additive result of the Dispatch Instructions deployed simultaneously. When deploying any Regulation, Responsive Reserve, or Non-Spinning Reserve Service, the QSE shall control its Resources to operate to the sum of the final Base Points plus any deployed Ancillary Service. Control performance of the QSE providing combined services must be determined by the criteria for each service outlined in Section 8.1.2.4, QSE Ancillary Service Energy Deployment Compliance Monitoring Criteria assuming actual Resource deployments first provide Regulation Service, then Responsive Reserve, and finally Non-Spin, as applicable.

8.1.3 Emergency Interruptible Load Service (EILS) Performance and Testing

8.1.3.1 Performance Criteria for EILS Loads

(1) EILS Loads' performance will be evaluated based on both their availability during a Contract Period and their performance during an EILS deployment event. As part of its evaluation of each EILS offer during an EILS procurement process, ERCOT will assign each EILS Load, including each ESI ID participating in an aggregated EILS Load, to a unique baseline. The baseline has three purposes:

(a) To verify or establish an EILS Load's maximum offer capacity;

(b) To provide the basis for ERCOT to determine the EILS Load's availability during its committed hours in a Contract Period; and

(c) To verify the EILS Load's performance, as compared to its contracted capacity, during an EILS deployment event.

(2) EILS Default Baseline:

(a) As part of its offer evaluation process, ERCOT will initially attempt to assign each EILS Load offer to a default baseline formula. The default baseline formula is designed to predict the interval Load based on variables which will include an ESI ID's historic Load data, weather, time of day and other relevant calendar information. ERCOT may use other data variables in the default baseline formula at ERCOT's sole discretion, if ERCOT determines the additional data will enhance the accuracy of the default baseline. Development of the default baseline for each EILS Load will be consistent with practices used in developing ERCOT Load Profile models. The methodology for developing the default baseline formula will be documented and published on the ERCOT website.

(b) ERCOT shall establish the default baseline for an aggregated EILS Load by adding the default baselines of the individual ESI IDs in the aggregation. The performance of an aggregated EILS Load shall be verified by ERCOT at the EILS Load level.

(c) ERCOT will develop a default baseline for each EILS Load by analyzing 15-minute interval usage data for the most recent 12-month period available. ERCOT may use additional historic data at its sole discretion. If ERCOT uses historical data pulled from its own systems to develop the default baseline for an EILS Load, ERCOT shall upon request provide the historical data used to the Entity responsible for that EILS Load.

(d) Based on ERCOT's analysis of data in establishing a default baseline for an EILS Load, ERCOT may reduce the amount of capacity an EILS Load may be awarded in a given EILS Contract Period.

(e) Upon request, ERCOT shall provide default baseline analysis results for an EILS Load to the Entity representing that EILS Load.

(3) Alternate Baseline:

(a) ERCOT may assign an EILS Load to a single alternate baseline formula if ERCOT determines that the EILS Load cannot be assigned to the default baseline with sufficient accuracy.

(b) Under the alternate baseline formula, ERCOT shall calculate an EILS Load's average (mean) IDR-metered Load (MWh) over the most recent available 12-month period, with an emphasis on the months corresponding to the upcoming Contract Period. ERCOT will validate the MW capacity offer for each EILS Load for the applicable EILS Time Period, based upon the difference between this average Load calculation (MWh) and the EILS Load's declared minimum base Load (MWh). In selecting an EILS Load with an alternate baseline, ERCOT may award the lesser of the MW offer or the MW capacity validated by ERCOT. When deployed by ERCOT, the EILS Load assigned to an alternate baseline shall curtail down to its minimum base Load or below, regardless of how much actual Load the EILS Load has online at the time of deployment.

(4) All ESI IDs within an aggregated EILS Load must be assigned to the same baseline methodology (either the default baseline or the alternate baseline).

(5) End of Contract Period Availability Review and Capacity Payment Adjustments:

(a) Within 45 days after the end of an EILS Contract Period, ERCOT will complete an availability review for each EILS Load that was contracted for that EILS Contract Period. In its availability review, ERCOT will determine an availability factor for each EILS Load in that EILS Contract Period.

(b) ERCOT will determine the availability factor for an EILS Load. An availability factor of 95% or greater for an EILS Load shall result in no reduction in capacity payment for the EILS Load (*i.e.*, ERCOT shall set the availability factor at 100%), and the EILS Load will be deemed to have complied with its availability requirements. If an EILS Load's availability factor for an EILS Contract Period falls below 95%, ERCOT shall set the EILS Load's availability factor at its actual availability factor, and the EILS Load will be deemed to have failed to meet its availability requirements which may result in a capacity payment adjustment. The calculations to determine the availability factor to be used for Settlement purposes are as follows:

$$\textbf{AvailFactor}_{\,qce(tp)r} = \textbf{1 if AvailFactor}_{\,qce(tp)} \textbf{ >= .95,}$$
$$\textbf{else AvailFactor}_{\,qce(tp)r} \textbf{ = AvailFactor}_{\,qce(tp)}$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	A QSE.
c	None	EILS Contract Period.
e	None	Individual EILS Load.
tp	None	EILS Time Period.
AvailFactor $_{qce(tp)}$	%	Availability factor for an EILS Load for an EILS Time Period, as calculated pursuant to the following subsections.
AvailFactor $_{qce(tp)r}$	%	Revised availability factor for an EILS Load for an EILS Time Period.

(c) For an EILS Load assigned to the default baseline, ERCOT will calculate its availability factor as follows:

(i) ERCOT will consider the EILS Load to have been available for any hour in a contracted EILS Time Period in which the EILS Load's IDR-metered Load was greater than 95% of its contracted EILS MW capacity (offer capacity plus declared minimum base Load); otherwise, the EILS Load will be considered unavailable for that hour. The availability factor will be the ratio of the number of hours the EILS Load was available during the EILS Contract Period divided by the total hours in the EILS Contract Period.

(ii) Notwithstanding the foregoing, in determining availability factor, ERCOT will consider the EILS Load to have been available for any of the following contracted hours:

(A) Any hours for which the EILS Load's QSE notified ERCOT, in a format prescribed by ERCOT, of the EILS Load's unavailability at least five Business Days in advance, up to a maximum of 2% of the total contracted hours in the EILS Contract Period;

(B) Any hours in which an Emergency Electric Curtailment Plan (EECP) was in effect, starting with initiation of Step 1 and including the full EILS recovery period, if applicable; and

(C) Any hours following the second EILS deployment in an EILS Contract Period.

(d) For an EILS Load assigned to the alternate baseline, ERCOT will calculate its availability factor as follows:

(i) ERCOT shall divide the EILS Load's actual average Load per hour (excluding its declared minimum base Load, if any) for the contracted hours in the EILS Time Period EILS Load's contracted MW offer, provided that the availability factor shall not be greater than one.

(ii) In determining the EILS Load's average actual Load,

(A) ERCOT shall exclude from the average any hours for which the EILS Load's QSE notified ERCOT, in a format prescribed by ERCOT, of the EILS Load's unavailability at least five Business Days in advance, up to a maximum of 2% of the total contracted hours in the EILS Contract Period;

(B) Any hours in which an EECP was in effect, starting with initiation of Step 1 and including the full EILS recovery period, if applicable; and

(C) Any hours following the second EILS deployment in an EILS Contract Period.

(iii) The calculations for the alternate baseline availability factor are as follows:

$$\textbf{AvailFactor}_{\,qce(tp)} = \textbf{MIN (1, (AV}_{(tp)} \textbf{ / (h*OFFERValue}_{\,qce(tp)}\textbf{)))}$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	A QSE.
c	None	EILS Contract Period.
e	None	Individual EILS Load.
tp	None	EILS Time Period .
h	Hour	An hour.
AV_{tp}	MWh	Average Load per hour for an EILS Load in a contracted EILS Time Period, excluding declared minimum base Load.
$OFFERValue_{qce(tp)}$	MW	An EILS Load's contracted capacity for an EILS Time Period.

AvailFactor $_{qce(tp)}$	%	Availability factor for an EILS Load for an EILS Time Period.

(e) In the event an EILS Load that is part of a QSE's EILS Self-Provision obligation fails to meet its availability requirement for a Contract Period, ERCOT shall adjust the EILS Load's QSE's Settlement obligation to reflect the actual availability factor by modifying the term "SP" in paragraph (2) of Section 6.6.11, Emergency Interruptible Load Service Settlement. An EILS Load that is part of a QSE's EILS Self-Provision that achieves an availability factor of 0.95 or greater shall be considered to have met its availability requirement.

(6) EILS Loads' Compliance During an EILS Deployment Event and Capacity Payment Adjustments:

(a) Upon ERCOT's issuance of a Verbal Dispatch Instruction (VDI) during EECP Step 3 requesting EILS deployment, EILS Loads assigned to the default baseline must curtail at least 95% of available contracted capacity within ten minutes of receiving the VDI and must stay at or below that level until released by ERCOT. EILS Loads assigned to the alternate baseline must curtail to their declared minimum base Load or below, and must stay at or below that level until released by ERCOT.

(b) ERCOT shall measure each EILS Load's compliance with this requirement through analysis of 15-minute IDR data from each ESI ID. ERCOT will determine an event performance factor for each EILS Load based upon this analysis.

(c) For an EILS Load assigned to a default baseline, the event performance factor (EILFactor) is computed as the arithmetic average of the EILS Interval Performance Factors (EIPF) for the entire curtailment period. An EIPF is computed for the EILS Load for each of the 15-minute intervals during which an EILS curtailment is required. For an interval, EIPF $_i$ is computed as follows:

$$\mathbf{EIPF}_{i} = \mathbf{Max(Min(((Base\_MWh}_{i} - \mathbf{Actual\_MWh}_{i}) / (\mathbf{IntFrac}_{i} * \mathbf{OFFERValue)),1),0)}$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	An interval.
IntFrac $_i$	None	Interval fraction for that EILS Load for that interval.
Base_MWh $_i$	MWh	Aggregated sum of the baseline MWh values estimated by ERCOT for all ESI IDs in the EILS Load for that interval.
Actual_MWh $_i$	MWh	Aggregated sum of the actual MWh values for all ESI IDs in the EILS Load for that interval.
OFFERValue	MWh	The EILS Load's contracted capacity.

and where IntFrac $_i$ corresponds to the fraction of time for that interval for which the curtailment period is in effect and is computed as follows:

$$\textbf{IntFrac}_{\textbf{\textit{i}}} = (\textbf{CEndT}_{\textbf{\textit{i}}} - \textbf{CbegT}_{\textbf{\textit{i}}}) / 15$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	An interval.
IntFrac $_i$	None	Interval fraction for that EILS Load for that interval.
CBegT $_i$	Minutes	If the curtailment begins after the start of that interval, the time in minutes from the beginning of that interval to the beginning of the curtailment period, otherwise it is zero.
CEndT $_i$	Minutes	If the curtailment ends during that interval, the time in minutes from the beginning of that interval to the end of the curtailment period, otherwise it is 15.

(d) For an EILS Load assigned to an alternate baseline, the EILFactor is computed as the arithmetic average of the EILS Interval Performance Factors (EIPF) for the entire curtailment period. An EIPF is computed for the EILS Load for each of the 15-minute intervals during which an EILS curtailment is required. For an interval, EIPF $_i$ is computed as follows:

(i) For the first interval in the curtailment period,

If Actual_MWh $_i$ = 0 then EIPF $_i$ = 1,

Otherwise

$$\textbf{EIPF}_{\textbf{\textit{i}}} = \textbf{Min((((1-IntFrac}_{\textbf{\textit{i}}}\textbf{) * Actual\_MWh}_{\textbf{\textit{i-1}}} \textbf{ + (IntFrac}_{\textbf{\textit{i}}} \textbf{ * Min\_MWh)) / Actual\_MWh}_{\textbf{\textit{i}}}\textbf{),1)}$$

(ii) For the last interval in the curtailment period,

If Actual_MWh $_i$ = 0 then EIPF $_i$ = 1,

Otherwise

$$\textbf{EIPF}_{\textbf{\textit{i}}} = \textbf{Min((((1-IntFrac}_{\textbf{\textit{i}}}\textbf{) * Actual\_MWh}_{\textbf{\textit{i+1}}} \textbf{ + (IntFrac}_{\textbf{\textit{i}}} \textbf{ * Min\_MWh)) / Actual\_MWh}_{\textbf{\textit{i}}}\textbf{),1)}$$

(iii) For all other intervals in the curtailment period

If Actual_MWh $_i$ = 0 then EIPF $_i$ = 1,

Otherwise

$$\textbf{EIPF}_{\textbf{\textit{i}}} = \textbf{Min(Min\_MWh / Actual\_MWh}_{\textbf{\textit{i}}}\textbf{),1)}$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	An interval.
IntFrac $_i$	None	Interval fraction for that EILS Load for that interval.
Min_MWh	MWh	Aggregated sum of the minimum base Load in MWh values contracted for all ESI IDs in the EILS Load for that interval.
Actual_ MWh $_i$	MWh	Aggregated sum of the actual MWh values for all ESI IDs in the EILS Load for that interval.

(iv) Where IntFrac $_i$ corresponds to the fraction of time for that interval for which the curtailment period is in effect, computed as follows:

$$\textbf{IntFrac}_{\boldsymbol{i}} = (\textbf{CEndT}_{\boldsymbol{i}} - \textbf{CBegT}_{\boldsymbol{i}}) / 15$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	An interval.
IntFrac $_i$	None	Interval fraction for that EILS Load for that interval.
CBegT $_i$	Minutes	If the curtailment begins after the start of that interval, the time in minutes from the beginning of that interval to the beginning of the curtailment period, otherwise it is zero.
CEndT $_i$	Minutes	If the curtailment ends during that interval, the time in minutes from the beginning of that interval to the end of the curtailment period, otherwise it is 15.

(e) In the event that an EILS Load does not meet its performance obligations according to the appropriate methodology described above, ERCOT may, in its sole discretion, adjust the EILS Load's event performance factor to reflect the severity of the failure. The event performance factor for an EILS Load may be any number from zero to one, inclusive. An EILS Load that achieves an event performance factor of 0.95 or greater shall be considered to have met its performance obligations for that event.

(f) In any EILS Contract Period in which ERCOT has issued one or more EILS deployments, if an EILS Load meets its event performance requirements as described in this subsection for all EILS deployments, ERCOT shall establish the EILS Load's availability factor at the availability factor calculated by ERCOT or 50%, whichever is greater. For any such EILS Load, ERCOT shall apply the calculations below for an EILS Contract Period in which there was at least one EECP event in which ERCOT deployed EILS:

$$\textbf{AvailFactor}_{\boldsymbol{qce(tp)r}} = \textbf{MAX(0.5, AvailFactor}_{\boldsymbol{qce(tp)}}\textbf{)}$$

The above variables are defined as follows:

Variable	Unit	Description

q	None	A QSE.
c	None	EILS Contract Period.
e	None	Individual EILS Load.
tp	None	EILS Time Period.
r	None	Revised pursuant to Subparagraph (e) or (f) above.
AvailFactor $_{qce(tp)}$	%	Availability factor for the EILS Load for the EILS Time Period as calculated by ERCOT pursuant to Subsection (5) above.
AvailFactor $_{qce(tp)r}$	%	Revised EILS availability factor for the EILS Load for the EILS Time Period.

(g) In the event an EILS Load that is part of a QSE's EILS Self-Provision obligation does not meet its performance requirement in an EILS deployment event, ERCOT shall adjust the Settlement obligation of the QSE representing the EILS Load to reflect the actual event performance factor by modifying the term "SP" in paragraph (3) of Section 6.6.11.2, Emergency Interruptible Load Service Capacity Charge. An EILS Load that is part of a QSE's EILS Self-Provision that achieves an event performance factor of 0.95 or greater shall be considered to have met its performance requirement for that EILS event.

8.1.3.2 Testing of EILS Loads

(1) ERCOT may conduct an unannounced Load-shedding test of any EILS Load at any time during an EILS Contract Period in which the EILS Load is contracted to provide EILS. Any such test will not be counted as one of the EILS Load's two maximum deployments in a Contract Period. A Load-shedding test shall be deemed to be successful if the EILS Load meets its event performance criteria as defined in paragraph (6) of Section 8.1.3.1, Performance Criteria for EILS Loads. An EILS Load that successfully completes an ERCOT-conducted Load-shedding test shall not be subject to an additional Load-shedding test for at least 365 days. In addition, an EILS Load that meets its performance obligations during any EILS deployment event shall not be subject to a full Load-shedding test for at least the following 365 days.

(2) ERCOT may conduct an unannounced Load-shedding test of a Load or aggregation of Loads that has been suspended from participation in EILS pursuant to Section 8.1.3.3, Suspension of Qualification of EILS Loads and/or their QSEs. ERCOT will conduct such a test only after the QSE representing the Load or aggregation has communicated to ERCOT a request for reinstatement of the suspended EILS Load.

8.1.3.3 Suspension of Qualification of EILS Loads and/or their QSEs

(1) If ERCOT determines that an EILS Load has failed to meet its performance or availability obligations, ERCOT shall suspend the EILS Load's qualification to participate in EILS for six months. If ERCOT determines that a QSE representing an EILS Load has failed to meet its EILS obligations under these Protocols, ERCOT shall

suspend the QSE's ability to represent EILS Loads for six months. Such suspension may be based on performance during an EILS deployment, the amount of capacity available, the number of hours available, or a combination of the above. ERCOT may consider mitigating factors such as equipment failures and Force Majeure Events in determining whether to assess such penalties. If the EILS Load or QSE is actively providing EILS at the time it failed to meet its obligations, the six-month suspension period shall commence at the end of the current Contract Period. If the EILS Load or QSE is not providing EILS at the time it failed to meet its obligations, the six-month suspension period shall begin immediately upon the finding.

(2) If ERCOT suspends qualification of an EILS Load or a QSE representing an EILS Load due to failure to meet performance obligations, ERCOT may revoke and recoup all payments for the EILS Contract Period associated with that EILS Load.

(3) ERCOT may reinstate an EILS Load's eligibility to offer into EILS only after the EILS Load satisfactorily performs a Load-shedding test conducted by ERCOT, as described in Section 8.1.3.2, Testing of EILS Loads.

8.1.3.4 ERCOT Data Collection for EILS

(1) ERCOT will collect all data necessary to analyze offers, Self-Provision offers, and all availability and performance obligations of EILS Loads and their QSEs under the Protocols. QSEs and EILS Loads they represent are required to provide any data to ERCOT that ERCOT may require, as specified by ERCOT.

(2) ERCOT shall post to the MIS Certified Area a summary of each QSE's EILS Load availability and performance for each Contract Period.

8.2 ERCOT Performance Monitoring and Compliance

(1) The Independent Market Monitor (IMM) shall continuously assess ERCOT operations and report to all Market Participants on the MIS Secure Area. The IMM shall report on ERCOT's compliance with its duties and obligations under these Protocols without undue discrimination, including its performance of the following activities:

- (a) Coordinating the wholesale electric market transactions;
- (b) System-wide transmission planning; and
- (c) Network reliability functions in the ERCOT Region.

(2) TAC, or a subcommittee designated by TAC, shall continually review the IMM's assessments of ERCOT's operations and ERCOT's performance in controlling the ERCOT Control Area according to requirements and criteria established by the Operating Guides and NERC policy and standards operating of Control Areas. Any reports that the IMM delivers to TAC on ERCOT's operations and performance must be posted to the MIS Secure Area by ERCOT. Reports of all substandard ERCOT operations must be

provided to TAC, the ERCOT Board and to the NERC Board as appropriate. Assessments and reports include the following ERCOT activities:

(a) Transmission control:

(i) Transmission system availability objectives;

(ii) Outage scheduling metrics including requests for Transmission Facilities Outages (maintenance planning, construction coordination, etc.);

(iii) NERC transmission metrics (e.g., monitoring and managing rated paths);

(iv) Other transmission monitoring and control metrics;

(v) Metrics describing how to minimize uplift to markets caused by transmission operations; and

(vi) Metrics describing performance of the State Estimator.

(b) Resource control:

(i) Regulation control metrics:

(A) NERC control performance;;

(B) Average sum of Reg-Up and Reg-Down energy near zero; and

(C) Total amount of Reg-Up energy deployed and the total amount of Reg-Down energy deployed in each Settlement Interval.

(ii) Metrics for Reserve monitoring as described in Section 8.1, QSE/Resource Performance Monitoring and Compliance;

(iii) Metrics describing RUC commitments and deployments;

(iv) Metrics describing the performance of Dynamically Scheduled Resources;

(v) Metrics describing conflicting instructions to Generation Resources from interval to interval;

(vi) NERC generation control metrics for the ERCOT Control Area (e.g., CPS, and DCS or their successors); and

(vii) Metrics describing the overall Resource response to frequency deviations in the ERCOT Region.

(c) Load forecasting;

(i) The accuracy of each day's Load forecast posted at 0600 in the Day-Ahead of the Operating Day as compared with the actual ERCOT Load for each hour of the Operating Day; and

(ii) Accuracy of the Load forecast used for Day-Ahead RUC compared to the actual ERCOT Load for each hour of the Operating Day.

(iii) The accuracy of the Load forecast for the following items compared to the average of the State Estimator Load at each Electrical Bus for each hour:

(A) Hourly Load forecast used in the Day-Ahead RUC by Load Zone;

(B) Hourly Load forecast used in the Day-Ahead RUC by Weather Zone;

(C) Hourly Load forecast used in the Hourly RUC by Load Zone;

(D) Hourly Load forecast used in the Hourly RUC by Weather Zone;

(E) The accuracy of the Load forecast used in the Day-Ahead RUC for the largest MW and MVA differences between the hourly Bus Load Forecast and the Real-Time Load at each Electrical Bus, by Load Zone; and

(F) The accuracy of the Load forecast used in the Day-Ahead RUC for the largest MW and MVA differences between the hourly Bus Load Forecast and the Real-Time Load at each Electrical Bus, by Weather Zone.

(d) System Operating Constraints:

(i) Comparison of system operating limits identified as constraining limits in the Day-Ahead Market to system operating limits identified as constraining limits in the Real-Time Market;

(ii) Comparison of system operating limits identified as constraining limits in the Hourly RUC to system operating limits identified as constraining limits in the Real-Time Market;

(iii) Comparison of system operating limits identified as constraining limits in the Day-Ahead RUC to the level the corresponding system parameter was operated in the Real-Time Market; and

(iv) Comparison of system operating limits identified as constraining limits in the Hour-Ahead Market to the level the corresponding system parameter was operated in the Real-Time Market.

(e) Settlement stability:

(i) Track number of price changes “after-the-fact;”

(ii) Track number and types of disputes submitted to ERCOT;

(iii) Report on compliance with timeliness of response and disposition of disputes;

(iv) Other settlement metrics; and

(v) Availability of ESI ID consumption data in conformance with settlement timeline.

(f) Performance in implementing network model updates;

(g) Network Operations Model validation, by comparison to other appropriate models or other methods;

(h) Back-up control plan;

(i) Written Black-Start plan;

(j) SAS 70 audit results; and

(k) Computer and communication systems Real-Time availability and systems security.

8.3 TSP Performance Monitoring and Compliance

(1) ERCOT shall develop a TAC-approved TSP Monitoring Program to be included in the Operating Guides for TSPs. The metrics developed by ERCOT must include the following elements of transmission system planning, operations and maintenance:

(a) Transmission Element rating calculations;

(b) Real-Time data:

(i) Meeting telemetry standards, including the installation of new measurement equipment and the accuracy of measurements;

(ii) Communications system availability; and

(c) Outage scheduling and coordination; TSP Outage planning and scheduling statistics must have less weight the further out these statistics are from the Planned Outage date;

(d) Compliance with model update requirements, including provision of network data in CIM compatible format and consistency with the Transmission Element naming convention developed in accordance under Section 3, Management Activities for the ERCOT System.

(e) Availability of TSP charges for each ESI ID;

(f) Written Black Start procedures and system capacity and energy emergency procedures;

(g) Back-up control plan;

(h) Compliance with Dispatch Instructions;

(i) Voltage and Reactive control performance; and

(j) Other NERC standards and Operating Guides requirements, as applicable.

8.4 Non-Compliance

(1) Reports of all activities that do not meet the performance criteria in this Section and in the Operating Guides must be provided to TAC, the ERCOT Board, the PUCT and to the NERC Board as appropriate. Non-compliance reports must be posted on the MIS Secure Area on delivery.

(2) ERCOT may require a Market Participant to develop and implement a corrective action plan to address its failure to meet performance criteria in this Section. The Market Participant must deliver a copy of this plan to ERCOT and must report to ERCOT periodically on the status of the implementation of the corrective action plan.

(3) ERCOT may revoke any or all Ancillary Service qualifications of any Generation Resource or Load Resource for continued material non-performance in providing Ancillary Service capacity or energy.

8.5 Frequency Response Requirements and Monitoring

8.5.1 Generation Resource and QSE Participation

8.5.1.1 Governor in Service

At all times an All-Inclusive Generation Resource is On-Line, its turbine governor must remain in service and be allowed to respond to all changes in system frequency. A Generation Entity may not reduce governor response on an individual All-Inclusive Generation Resource during abnormal conditions without ERCOT's consent unless equipment damage is imminent.

8.5.1.2 Reporting

(1) Each Generation Entity shall conduct applicable generating governor speed regulation tests on each of its Generation Resources as specified in the Operating Guides. Test results and other relevant information shall be reported to ERCOT and ERCOT shall forward results to the appropriate TSPs.

(2) Generation Resource governor modeling information required in the ERCOT planning criteria must 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 must be supplied to ERCOT and the connected TSP.

(3) When the governor of a Generation Resource is blocked while the Resource is operating, the QSE shall promptly inform ERCOT. The QSE shall also supply governor status logs to ERCOT upon request.

(4) Any short-term inability of a Generation Resource to supply governor response must be immediately reported to ERCOT by the Generation Resource's QSE.

(5) If a Generation Resource trips Off Line due to governor response problems, the QSE shall immediately report the change in the status of the Resource to ERCOT.

8.5.2 Primary Frequency Control Measurements

(1) For the purposes of this Section 8.5.2, the A Point is the last stable frequency value before a frequency disturbance. ERCOT shall determine the A Point frequency for each event using the following standards.

(a) For a decreasing frequency event with the last stable frequency value of 60.000 Hz or below, the actual frequency is used as the A Point.

(b) For a decreasing frequency event with the last stable frequency value between 60.000 and 60.036 Hz, 60.000 Hz is used as the A Point.

(c) For a decreasing frequency event with the last stable frequency value above 60.036 Hz, actual frequency is used as the A Point.

(d) For an increasing frequency event with the last stable frequency value of 60.000 or above, the actual frequency is used as the A Point.

(e) For an increasing frequency event with the last stable frequency between 59.964 and 60.000 Hz, 60.000 Hz will be used as the A Point.

(f) For an increasing frequency event with the last stable frequency value of 59.964 or below, the actual frequency is used as the A Point.

(2) For the purposes of this section, the C Point is the lowest frequency value during the first five seconds of the event. ERCOT shall determine the C Point for each event.

(3) For the purposes of this section, the B Point is the "recovery" frequency value after the C Point. The B Point should occur after full governor response of the turbines has occurred, usually between ten and 30 seconds after the A Point, but not greater than 60 seconds after the A Point. ERCOT shall determine the B Point for each event.

(4) ERCOT, with the assistance of the appropriate ERCOT subcommittee, shall analyze whether primary frequency control response is sustained at 30 seconds following the B Point.

(5) For the purposes of this section, a "Measurable Event" that will be evaluated for performance compliance is a sudden change in frequency that has both:

(a) A frequency B Point between 59.700 Hz and 59.900 Hz or between 60.100 Hz and 60.300 Hz; and

(b) A difference between the B Point and the A Point greater than or equal to +/- 0.100 Hz.

8.5.2.1 ERCOT Required Primary Frequency Control Response

(1) The combined response of all Generation Resources in ERCOT to a Measurable Event must be at least 420 MW / 0.1 Hz. This value should be reviewed on an annual basis by ERCOT and the appropriate ERCOT subcommittee for ERCOT System reliability needs.

(2) ERCOT shall evaluate, with the assistance of the appropriate ERCOT subcommittee, primary frequency control response during Measurable Events. The actual Generation Resource response must be compiled to determine if adequate primary frequency control participation was available.

(3) ERCOT and the appropriate ERCOT subcommittee shall review each Measurable Event, verifying the reasonableness of data. Data that is in question may be requested from the QSE for comparison or individual Generation Resource data may be retrieved from ERCOT's database.

(4) ERCOT's performance must be averaged using the most recent six Measurable Events to determine its rolling average contribution.

8.5.2.2 ERCOT Data Collection

ERCOT shall collect all data necessary to analyze each Measurable Event.

ERCOT Nodal Protocols

Section 9: Settlement and Billing

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's] Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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9 SETTLEMENT AND BILLING

9.1 General

9.1.1 Settlement and Billing Process Overview

Settlement is the process used to resolve financial obligations between a Market Participant and ERCOT, including administrative and miscellaneous charges. Settlement also provides Transmission Billing Determinants to Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs). The Settlement and billing timeline and process for the Day-Ahead Market (DAM) is separate from the Settlement and billing timeline and process for the Day-Ahead Reliability Unit Commitment (DRUC) process, the Adjustment Period, and Real-Time operations (after this referred to together in this Section as the Real-Time Market).

9.1.2 Settlement Calendar

(1) ERCOT shall post and maintain on the Market Information System (MIS) Public Area a "Settlement Calendar" to denote, for each Operating Day, when:

(a) Each scheduled Settlement Statement for the Day-Ahead Market (DAM) will be issued under Section 9.2.4, DAM Statement, and Section 9.2.5, DAM Resettlement Statement;

(b) Each Settlement Invoice for the DAM will be issued under Section 9.3, Settlement Invoices for the DAM;

(c) Payments for the DAM are due under Section 9.4, Payment Process for the DAM;

(d) Each Late Fee Invoice for the DAM will be issued under Section 9.4.5, Late Fees and Late Fee Invoices for the DAM;

(e) Payments for DAM Late Fee Invoices are due under Section 9.4.5;

(f) Each scheduled Settlement Statement for the Real-Time Market (RTM) will be issued under Section 9.5.4, RTM Initial Statement, Section 9.5.5, RTM Final Statement, Section 9.5.6, RTM Resettlement Statement, and Section 9.5.8, RTM True-Up Statement;

(g) Each Settlement Invoice for the RTM will be issued under Section 9.6, Settlement Invoices for the Real-Time Market;

(h) Payments for the Real-Time Market are due under Section 9.7, Payment Process for the RTM;

(i) Each Late Fee Invoice for the RTM will be issued under Section 9.7.5, Late Fees and Late Fee Invoices for the RTM;

(j) Payments for RTM Late Fee Invoices are due under Section 9.7.5;

(k) Each RTM Uplift Invoice will be issued under Section 9.7.3, Partial Payments by Invoice Recipients for the RTM;

(l) Payments for RTM Uplift Invoices are due under Section 9.7.3;

(m) Each Congestion Revenue Rights (CRR) Auction Invoice will be issued under Section 9.8, CRR Auction Invoices;

(n) Payments for CRR Auction Invoices are due under Section 9.9, Payment Process for CRR Auction Invoices;

(o) Each CRR Auction Revenue Distribution Invoice will be issued under Section 9.10, CRR Auction Revenue Distribution Invoices;

(p) Payments for CRR Auction Revenue Distribution Invoices are due under Section 9.11, Payment Process for CRR Auction Revenue Distribution;

(q) Each CRR Balancing Account Invoice will be issued under Section 9.12, CRR Balancing Account Invoices;

(r) Payments for CRR Balancing Account Invoices are due under Section 9.13, Payment Process for the CRR Balancing Account; and

(s) Settlement and Billing Disputes for each scheduled Settlement Statement of an Operating Day and Settlement Invoice must be submitted under Section 9.14, Settlement and Billing Dispute Process.

(2) ERCOT shall notify Market Participants if any of the aforementioned data will not be available on the date specified in the Settlement Calendar.

9.1.3 Settlement Statement and Invoice Access

A Statement or Invoice Recipient may access its Settlement Statements or Invoices electronically, using either of the following methods:

(a) Secured entry on the MIS Certified Area;

(b) eXtensible Markup Language (XML) access to the MIS Certified Area.

9.1.4 Settlement Statement and Invoice Timing

Unless expressly stated otherwise, the publication of each Settlement Statement and Invoice can occur as late as 2400 on its scheduled publication date.

9.1.5 Settlement Payment Convention

A Settlement Statement or Invoice containing a negative amount represents a payment due by ERCOT to the Market Participant that received the Statement or Invoice. A Settlement Statement or Invoice containing a positive amount represents a payment due to ERCOT by the Market Participant that received the Statement or Invoice.

9.2 Settlement Statements for the Day-Ahead Market

9.2.1 Settlement Statement Process for the DAM

ERCOT shall produce daily Settlement Statements for the Day-Ahead Market (DAM), as defined in Section 9.2.2, Settlement Statements for the DAM, that show a breakdown of Charge Types incurred in the DAM, including any administrative and miscellaneous charges applicable to the DAM. "Charge Types" are the various categories of specific charges referenced in Section 9.15.1, Charge Type Matrix.

9.2.2 Settlement Statements for the DAM

(1) ERCOT shall make each Settlement Statement for a DAM available on the date specified on the Settlement Calendar for that DAM by posting it on the Market Information System (MIS) Certified Area for the applicable Market Participant to which the Settlement Statement is addressed (Statement Recipient).

(2) A Settlement Statement for the DAM can be:

(a) A "DAM Statement," which is the Settlement Statement issued for a particular DAM;

(b) A "DAM Resettlement Statement," which corrects a DAM Statement.

(3) The Statement Recipient is responsible for accessing the statement from the MIS Certified Area.

(4) ERCOT shall create a DAM Statement for each DAM.

(5) ERCOT may create a DAM Resettlement Statement for the DAM, depending on the criteria set forth in Section 9.2.5, DAM Resettlement Statement.

(6) Each Settlement Statement for the DAM must denote:

(a) The applicable Operating Day;

(b) The Statement Recipient's name;

(c) The ERCOT identifier (settlement identification number issued by ERCOT);

(d) Status of the statement (DAM Statement or DAM Resettlement Statement);

(e) Statement version number;

(f) Unique statement identification code; and

(g) Charge Types settled.

(7) Settlement Statements for the DAM must break fees down by Charge Types into the appropriate one-hour Settlement Interval for that type.

(8) The Settlement Statement for the DAM must have a summary page of the corresponding detailed documentation.

9.2.3 DAM Settlement Charge Types

ERCOT shall provide, on each Settlement Statement, the dollar amount for each DAM Settlement charge and payment. The DAM settlement "Charge Types" are:

(a) Section 4.6.2.1, Day-Ahead Energy Payment;

(b) Section 4.6.2.2, Day-Ahead Energy Charge;

(c) Section 4.6.2.3.1, Day-Ahead Make-Whole Payment;

(d) Section 4.6.2.3.2, Day-Ahead Make-Whole Charge;

(e) Section 4.6.3, Settlement for PTP Obligations Bought in DAM;

(f) Section 4.6.4.1.1, Regulation Up Service Payment;

(g) Section 4.6.4.1.2, Regulation Down Service Payment;

(h) Section 4.6.4.1.3, Responsive Reserve Service Payment;

(i) Section 4.6.4.1.4, Non-Spinning Reserve Service Payment;

(j) Section 4.6.4.2.1, Regulation Up Service Charge;

(k) Section 4.6.4.2.2, Regulation Down Service Charge;

(l) Section 4.6.4.2.3, Responsive Reserve Service Charge;

(m) Section 4.6.4.2.4, Non-Spinning Reserve Service Charge;

(n) Section 7.9.1.1, Payments and Charges for PTP Obligations Settled in DAM;

(o) Section 7.9.1.2, Payments for PTP Options Settled in DAM;

(p) Section 7.9.1.4, Payments for FGRs Settled in DAM;

(q) Section 7.9.1.5, Payments and Charges for PTP Obligations with Refund Settled in DAM;

(r) Section 7.9.1.6, Payments for PTP Options with Refund Settled in DAM; and

(s) Section 7.9.3.3, Shortfall Charges to CRR Owners in DAM, Item 2 and Item 4.

9.2.4 DAM Statement

ERCOT shall produce a DAM Statement for each Statement Recipient for the given DAM on the second Business Day after the Operating Day.

9.2.5 DAM Resettlement Statement

(1) ERCOT shall issue DAM Resettlement Statements for a given DAM if the ERCOT Board finds that the DAM Locational Marginal Prices (LMPs), Market Clearing Prices for Capacity (MCPCs), or Settlement Point Prices are significantly affected by a software or data error under Section 4.5.3, Communicating DAM Results. ERCOT shall also produce DAM Resettlement Statements required by resolution of Settlement and Billing disputes.

(2) ERCOT shall issue a DAM Resettlement Statement for a given DAM due to error in data other than prices when the total of all errors in data other than prices results in an impact greater than 2% of the total payments due to ERCOT for the DAM, excluding bilateral transactions. ERCOT shall issue DAM Resettlement Statements as soon as possible to correct the errors. ERCOT shall review this percentage on an annual basis. Upon the review, ERCOT may make a recommendation to revise this percentage under Section 21, Process for Protocol Revision.

(3) A DAM Resettlement Statement must reflect differences to financial records generated on the previous Settlement Statement for the given DAM.

9.2.6 Notice of Resettlement for the DAM

While maintaining confidentiality of all Market Participants, ERCOT shall post a notice on the MIS Public Area no later than one Business Day after the declaration of the resettlement, indicating that the DAM for a specific Operating Day will be resettled and the date that the DAM Resettlement Statements for that DAM will be issued by ERCOT. ERCOT shall include the following information in the notice of resettlement:

(a) Detailed description of reason(s) for resettlement;

(b) For the applicable Operating Day;

(c) Affected Charge Types; and

(d) Total resettled amount, by Charge Type.

9.2.7 Confirmation of Statement for the DAM

It is the responsibility of each Statement Recipient to notify ERCOT if a Settlement Statement for the DAM is not available on the MIS Certified Area on the date specified for posting of that Settlement Statement in the Settlement Calendar. Each Settlement Statement for the DAM is deemed to have been available on the posting date specified on the Settlement Calendar, unless ERCOT is notified to the contrary. If ERCOT receives notice that a Settlement Statement is not available, ERCOT shall make reasonable attempts to provide the Settlement Statement to the Statement Recipient, and ERCOT shall modify the Settlement and billing timeline accordingly for that Settlement Statement.

9.2.8 Validation of the Settlement Statement for the DAM

The Statement Recipient is deemed to have validated each Settlement Statement for the DAM unless it has raised a Settlement and billing dispute under Section 9.14.

9.2.9 Suspension of Issuing Settlement Statements for the DAM

The ERCOT Board may direct ERCOT to suspend the issuance of any Settlement Statement for the DAM to address unusual circumstances. Any proposal to suspend settlements must be presented to the Technical Advisory Committee (TAC) for review and comment, in a reasonable manner under the circumstances, prior to such suspension.

9.3 Settlement Invoices for the DAM

(1) ERCOT shall issue Invoices for the DAM (DAM Invoice) on the second Business Day after the Operating Day. For each DAM Invoice, the Market Participant to whom the Invoice is addressed ("Invoice Recipient") is either a payee or payor. The Invoice Recipient is responsible for accessing the Invoice on the MIS Certified Area once posted by ERCOT.

(2) ERCOT shall issue DAM Invoices that are based on DAM Resettlement Statements on the same Business Day as the day that the DAM Resettlement Statement is posted to the MIS Certified Area.

(3) Each DAM Invoice must contain:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due or Payable – the aggregate summary of all charges owed by, or due to, an Invoice Recipient for that DAM;

(d) Time Periods – the time period covered for each line item;

(e) Run Date – the date in which the DAM Invoice was created and published;

(f) Invoice Reference Number – a unique number generated by the ERCOT applications for payment tracking purposes;

(g) Statement Reference – an identification code used to reference the Settlement Statement invoiced;

(h) Payment Date and Time – the date and time that DAM Invoice amounts must be paid or received;

(i) Remittance Information Details – details including the account number, bank name, and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due; and

(j) Overdue Terms – the terms that would be applied if payments were received late.

9.4 Payment Process for the DAM

Payments for the DAM must be made on days that are both a Business Day and a Bank Business Day in a two-day, two-step process as detailed below. Payments for the DAM are due on the applicable payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the payment.

9.4.1 Invoice Recipient Payment to ERCOT for the DAM

(1) The payment due date and time for the DAM Invoice, with funds owed by an Invoice Recipient, is 1700 on the fourth Bank Business Day after the DAM Invoice date, unless that fourth Bank Business Day is not a Business Day. If the fourth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fourth Bank Business Day that is also a Business Day.

(2) All DAM Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars by either of the following:

(a) On or before the payment due date if the payment is made by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal); or

(b) On or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House (ACH) funds.

9.4.2 ERCOT Payment to Invoice Recipients for the DAM

(1) Subject to the availability of funds as discussed in paragraph (2) below, DAM Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next Bank Business Day after payments are due for that DAM under Section 9.4.1, Invoice Recipient Payment to ERCOT for the DAM, subject to ERCOT's right to withhold payments under Section 16, Registration and Qualification of Market Participants, unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, then the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each Invoice Recipient for same day value, the amounts determined by ERCOT to be available for payment to that Invoice Recipient under paragraph (d) of Section 9.4.3, Partial Payments by Invoice Recipients for the DAM.

9.4.3 Partial Payments by Invoice Recipients for the DAM

If at least one Invoice Recipient owing funds does not pay its DAM Invoice in full (short-pays), then ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient before any payments owed by ERCOT for that DAM is due to be paid to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available security pledged to ERCOT by each short-paying Invoice Recipient that did not pay the amount due under paragraph (a) above.

(c) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT to a short-paying Invoice Recipient against amounts not paid by that Invoice Recipient, and ERCOT shall apply the amount offset or recouped to cover payment shortages by that Invoice Recipient.

(d) If, after taking the actions set forth in paragraphs (a), (b) and (c), above, ERCOT still does not have sufficient funds to pay all amounts that it owes to DAM Invoice Recipients in full, ERCOT shall deduct any applicable DAM administrative fees as specified in Section 9.16, Administrative Fees, payments for RMR Services and amounts calculated for the CRR Balancing Account from the amount received or collected and then reduce payments to all DAM Invoice Recipients owed monies from ERCOT. The reductions must be based on a pro rata basis of monies owed to each Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short payments and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the Invoice.

(e) One hundred eighty days following a short-payment of a DAM Invoice, if sufficient funds continue to be unavailable for ERCOT to pay all amounts in full (excluding late fees) to short-paid Entities for that DAM Invoice, and the short-paying Entity is not in compliance with a payment plan designed to enable ERCOT to pay all amounts in full (excluding late fees) to short-paid Entities, ERCOT will cease charging late fees to the defaulting Entity; provided that ERCOT may cease charging late fees earlier than 180 days following a short-payment of a DAM Invoice if ERCOT, in its sole discretion, determines that the recovery of late fees from the defaulting Entity is unlikely.

(f) When ERCOT enters into a payment plan with a short-pay Invoice Recipient, ERCOT shall post to the MIS Secured Area:

(i) The short-pay plan;

(ii) The schedule of quantifiable expected payments, updated if and when modifications are made to the payment schedule; and

(iii) Invoice dates to which the payments will be applied.

(g) To the extent ERCOT is able subsequently to collect past due funds owed by a short-paying Invoice Recipient, ERCOT shall allocate the collected funds to the earliest DAM Invoice for which that Invoice Recipient remains a short-payer. ERCOT shall use its best efforts to distribute collected past due funds on a pro rata basis of monies owed on the next Bank Business Day that is also a Business Day after receipt of the monies, when sufficient funds for the relevant DAM are available in this Settlement process.

9.4.4 Enforcing the Security of a Short-Paying Invoice Recipient

ERCOT shall make reasonable efforts to enforce the security of the short-paying Invoice Recipient (pursuant to Section 16.11.6, Payment Default and Late Payments by Counter-Parties) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its security under Section 16.

9.4.5 Late Fees and Late Fee Invoices for the DAM

(1) A short-paying DAM Invoice Recipient shall pay late fees to ERCOT on the short-pay amount according to the late fee terms specified in the ERCOT fee schedule that is posted on the MIS Public Area for the period from, and including, the relevant payment due date to the date on which the payment, including any related transaction costs incurred by ERCOT, is received by ERCOT. ERCOT will cease charging late fees to the defaulting Entity when the conditions described in item (e) of Section 9.4.3 are met.

(2) ERCOT shall distribute any late fee revenues, less ERCOT's transaction costs, to the DAM Invoice Recipients that were underpaid, due to a short-pay, on a pro rata basis of monies owed to each DAM Invoice Recipient.

(3) ERCOT shall post to the MIS Certified Area for each DAM Invoice Recipient, a DAM Invoice based on late fees (DAM Late Fee Invoice). The DAM Late Fee Invoice Recipient is responsible for accessing the information from the MIS Certified Area once posted by ERCOT.

(4) ERCOT shall issue DAM Late Fee Invoices on the tenth calendar day after the end of the month, unless the tenth day is not a Business Day. If that tenth day is not a Business Day, then ERCOT shall issue the DAM Late Fee Invoice of the next day thereafter that is a Business Day. ERCOT will post the actual dates on which it will issue DAM Late Fee Invoices under Section 9.1.2, Settlement Calendar.

(5) Each DAM Late Fee Invoice must contain:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due or Payable – the aggregate summary of all charges owed or due by an Invoice Recipient;

(d) Time Periods – the time period covered for each line item;

(e) Run Date – the date in which the Invoice was created and published;

(f) Invoice Reference Number – a unique number generated by the ERCOT applications for payment tracking purposes;

(g) Payment Date and Time – the date and time that Invoice amounts are to be paid or received;

(h) Remittance Information Details – details including the account number, bank name and electronic transfer instructions for the ERCOT account to which any amounts owed by the Invoice Recipient must be paid or of the Invoice Recipient's account from which ERCOT may draw payments due; and

(i) Overdue Terms – the terms that would apply if the Market Participant makes a late payment.

(6) Market Participants must make payments for DAM Late Fee Invoices on days that are both a Business Day and a Bank Business Day in a two-day, two-step process as detailed below. Payments for DAM Late Fee Invoices are due on the applicable payment due date, whether or not there is any Settlement and Billing dispute regarding the amount of the payment.

(a) The payment due date and time for the DAM Late Fee Invoice, with funds owed by an Invoice Recipient, is 1700 on the fourth Bank Business Day after the DAM Late Fee Invoice date, unless that fourth Bank Business Day is not a Business Day. If the fourth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fourth Bank Business Day that is also a Business Day.

(b) All DAM Late Fee Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars by either of the following:

(i) On or before the payment due date if the payment is made by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e. not subject to reversal); or

(ii) On or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House (ACH) funds.

(c) Subject to the availability of funds as discussed in paragraph (d) below, DAM Late Fee Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next Bank Business Day after payments are due for that DAM Late Fee Invoice under paragraph (a) above, subject to ERCOT's right to withhold payments under Section 16, unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, then the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(d) If at least one Invoice Recipient owing funds does not pay it's DAM Late Fee Invoice in full (short-pays), then ERCOT shall reduce payments to all DAM Late Fee Invoice Recipients owed monies from ERCOT. The reductions must be based on a pro rata basis of monies owed to each Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short payments and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the Invoice. ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each Invoice Recipient for same day value, the amounts determined by ERCOT to be available for payment.

9.5 Settlement Statements for Real-Time Market

9.5.1 Settlement Statement Process for the Real-Time Market

ERCOT shall produce daily Settlement Statements for the Real-Time Market (RTM), as defined in Section 9.5.2, Settlement Statements for the RTM, that show a breakdown of Charge Types incurred in the RTM, including any administrative and miscellaneous charges applicable to the RTM.

9.5.2 Settlement Statements for the RTM

(1) ERCOT shall make each Settlement Statement for the RTM for an Operating Day available on the date specified on the Settlement Calendar for that Operating Day by posting it to the MIS Certified Area for the applicable Statement Recipient.

(2) A Settlement Statement for the RTM can be:

(a) An "RTM Initial Statement," which is the first iteration of a Settlement Statement issued for a particular Operating Day;

(b) An "RTM Final Statement," which is the statement issued at the end of the 59th day following the Operating Day;

(c) An "RTM Resettlement Statement," which is the statement using corrected Settlement data due to resolution of disputes and correction of data errors; or

(d) An "RTM True-Up Statement," which is a statement issued at the end of the 180th day after the Operating Day.

(3) The Statement Recipient is responsible for accessing the Statement from the MIS Certified Area.

(4) To issue an RTM Settlement Statement, ERCOT may use estimated, disputed, or calculated meter data.

(5) ERCOT shall create an RTM Initial Statement, RTM Final Statement, and RTM True-Up Statement for each Operating Day.

(6) ERCOT may create an RTM Resettlement Statement for any Operating Day, depending on the criteria set forth in Section 9.5.6, RTM Resettlement Statement. When actual validated data is available and all of the Settlement and billing disputes raised by Statement Recipients in accordance with Section 9.8.4, ERCOT Processing of Disputes, during the validation process have been resolved, ERCOT shall recalculate the amounts payable and receivable by the affected RTM Statement Recipients, as described in Section 9.5.6.

(7) Each RTM Settlement Statement must denote:

(a) Operating Day;

(b) The Statement Recipient's name;

(c) The ERCOT identifier (settlement identification number issued by ERCOT);

(d) Status of the statement (Initial, Final, Resettlement, or True-Up);

(e) Statement version number;

(f) Unique statement identification code; and

(g) Charge Types settled.

(8) A Settlement Statement for the RTM must break the fees down by Charge Type into the appropriate 15-minute or one-hour Settlement Interval for that type.

(9) A RTM Settlement Statement must have a summary page of the corresponding detailed documentation.

9.5.3 Real-Time Market Settlement Charge Types

(1) When the DAM is executed, ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement "Charge Types" are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE -Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section 5.7.5, RUC Clawback Payment;

(g) Section 5.7.6, RUC Decommitment Charge;

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

(j) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;

(k) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time Energy Charge for DC Tie Export represented by the QSE under Oklaunion Exemption;

(n) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules;

(o) Section 6.6.5.1.1, Base Point Deviation Charge for Over Generation,

(p) Section 6.6.5.1.2, Base Point Deviation Charge for Under Generation,

(q) Section 6.6.5.2, IRR Generation Resource Base-Point Deviation Charge;

(r) Section 6.6.5.4, Base Point Deviation Payment;

(s) Section 6.6.6.1, RMR Standby Payment;

(t) Section 6.6.6.2, RMR Payment for Energy;

(u) Section 6.6.6.3, RMR Adjustment Charge;

(v) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(w) Section 6.6.6.5, RMR Service Charge;

(x) Paragraph (2) of Section 6.6.7.1, Voltage Support Service Payments;

(y) Paragraph (4) of Section 6.6.7.1, Voltage Support Service Payments;

(z) Section 6.6.7.2, Voltage Support Charge;

(aa) Section 6.6.8.1, Black Start Capacity Payment;

(bb) Section 6.6.8.2, Black Start Capacity Charge;

(cc) Section 6.6.9.1, Payment for Emergency Power Increase directed by ERCOT;

(dd) Section 6.6.9.2, Charge for Emergency Power Increases;

(ee) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(ff) Paragraph (1) of Section 6.7.1, Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Service Market;

(gg) Paragraph (2) of Section 6.7.1;

(hh) Paragraph (3) of Section 6.7.1;

(ii) Paragraph (4) of Section 6.7.1;

(jj) Paragraph (1) of Section 6.7.2, Charges for Ancillary Service Capacity replaced due to Failure to Provide;

(kk) Paragraph (2) of Section 6.7.2;

(ll) Paragraph (3) of Section 6.7.2;

(mm) Paragraph (4) of Section 6.7.2;

(nn) Paragraph (1) of Section 6.7.3, Adjustments to Cost Allocations for Ancillary Services Procurement;

(oo) Paragraph (2) of Section 6.7.3;

(pp) Paragraph (3) of Section 6.7.3;

(qq) Paragraph (4) of Section 6.7.3;

(rr) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time;

(ss) Section 7.9.2.2, Payments for PTP Options Settled in Real-Time;

(tt) Section 7.9.2.3, Payments for NOIE PTP Options with Refund Settled in Real-Time;

(uu) Section 7.9.3.3, Shortfall Charges to CRR Owners in Real-Time, Item 3;

(vv) Section 9.16.1.1, ERCOT System Administration Charge;

(ww) Section 9.16.5, ERCOT Nodal Implementation Surcharge.

(2) In the event that ERCOT is unable to execute the DAM, ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for the following RTM CRR Settlement charges and payments:

(a) Section 7.9.2.4, Payments for FGRs in Real-Time;

(b) Section 7.9.2.5, Payments and Charges for PTP Obligations with Refund in Real-Time.

9.5.4 RTM Initial Statement

ERCOT shall issue an RTM Initial Statement for each Statement Recipient for a given Operating Day on the tenth day after the Operating Day, unless that tenth day is not a Business Day. If the tenth day is not a Business Day, then ERCOT shall issue the RTM Initial Statement on the next Business Day after the tenth day.

9.5.5 RTM Final Statement

(1) ERCOT shall issue an RTM Final Statement for each Statement Recipient for a given Operating Day on the 59th day after the Operating Day, unless that 59th day is not a Business Day. If the 59th day is not a Business Day, then ERCOT shall issue the RTM Final Statement on the first Business Day after the 59th day.

(2) An RTM Final Statement will reflect differences to financial records generated on the previous Settlement Statement for the given Operating Day

9.5.6 RTM Resettlement Statement

(1) ERCOT shall issue a Real-Time Market (RTM) Resettlement Statement using corrected Settlement data due to resolution of disputes and correction of data errors. Any resettlement occurring after an RTM True-Up Statement has been issued must meet the same IDR Data Threshold requirements defined in Section 9.5.8, RTM True-Up Statement, and is subject to the same limitations for filing a dispute. Despite the preceding sentence, the ERCOT Board may, in its discretion, direct ERCOT to run a Resettlement of any Operating Day, at any time, to address unusual circumstances.

(2) ERCOT shall issue a RTM Resettlement Statement for a given Operating Day due to data error in data other than prices when the total of all errors in data other than prices results in an impact greater than 2% of the total payments due to ERCOT for the RTM for the Operating Day, excluding bilateral transactions. ERCOT shall issue RTM Resettlement Statements as soon as possible to correct the errors. ERCOT shall review this percentage on an annual basis. Upon the review, ERCOT may make a recommendation to revise this percentage under Section 21, Process for Protocol Revision.

(3) For any Settlement and Billing disputes resolved prior to issuance of the RTM Final Statement, ERCOT shall effect the dispute's resolution on the RTM Final Statement for that Operating Day. If a dispute is submitted by 15 Business Days after the issuance of the RTM Initial Statement for an Operating Day and is not resolved on the RTM Final Statement, ERCOT will effect the dispute's resolution on an RTM Resettlement Statement for that Operating Day. ERCOT shall issue such an RTM Resettlement Statement within a reasonable time after resolving the Settlement and Billing dispute.

(4) ERCOT must effect the resolution of any dispute submitted more than 15 Business Days after the issuance of the RTM Initial Statement on the next available Resettlement or RTM True-Up statement for that Operating Day. For Settlement and Billing disputes resolved under Section 9.14, Settlement and Billing Dispute Process, and submitted at least 20 Business Days before the scheduled date for issuance of the RTM True-Up Statement, ERCOT will include adjustments relating to the dispute on the RTM True-Up Statement. Resolved disputes must be included on the next available RTM Invoice after ERCOT has issued the RTM True-Up Statement.

(5) ERCOT may not issue an RTM Resettlement Statement less than 20 days before a scheduled RTM Final Statement or RTM True-Up Statement for the relevant Operating

Day. An RTM Resettlement Statement will reflect differences to financial records generated on the previous Settlement Statement for the given Operating Day.

9.5.7 Notice of Resettlement for the Real-Time Market

While maintaining confidentiality of all Market Participants, ERCOT shall post a notice of resettlement for the RTM on the MIS Public Area within one Business Day after the declaration of the resettlement, indicating that a specific Operating Day will be resettled and the date that the RTM Resettlement Statements will be issued by ERCOT. ERCOT shall include the following information in the notice of resettlement:

(a) Detailed description of reason(s) for resettlement;

(b) Affected Operating Days;

(c) Affected settlement Charge Types; and

(d) Total resettled amount, by Charge Type.

9.5.8 RTM True-Up Statement

(1) ERCOT shall use the best available Settlement data, as described in Section 9.5.2, to produce an RTM True-Up Statement for each Statement Recipient for each given Operating Day.

(2) ERCOT shall issue RTM True-Up Statements 180 days following the Operating Day, if ERCOT has received and validated at least 99% of the total IDR data and if ERCOT has received and validated at least 90% of the IDR data from each Meter Reading Entity (MRE) representing at least 20 IDR ESI IDs ("IDR Data Threshold"). If the above conditions have not been met, then ERCOT shall issue RTM True-Up Statements as soon as the IDR data becomes available for that Operating Day. If no RTM True-Up Statement has been issued 365 days after the Operating Day, then ERCOT shall issue a RTM True-Up Statement for that Operating Day. If any RTM True-Up Statement issuance date does not fall on a Business Day, then the RTM True-Up Statement must be issued by the end of the next Business Day after the RTM True-Up settlement date.

(3) An RTM True-Up Statement will reflect differences to financial records generated on the previous Settlement Statement for the given Operating Day.

9.5.9 Notice of True-Up Settlement Timeline Changes for the Real-Time Market

(1) If the IDR Data Threshold has not been met by the 180th day after the Operating Day (or, if the 180th day is not a Business Day, by the next day thereafter that is a Business Day), then ERCOT shall immediately post a notice of delay on the MIS Public Area of any RTM True-Up Statement issuance, indicating the IDR Data Threshold has not been met.

(2) For any delayed RTM True-Up Statement, ERCOT shall post a Notice of RTM True-Up Settlement on the MIS Public Area indicating that it will issue an RTM True-Up Statement for a specific Operating Day within two Business Days after discovering the delay. As soon as practicable, ERCOT shall post on the MIS Public Area the revised date on which the delayed RTM True-Up Statement will be issued.

9.5.10 Confirmation for the Real-Time Market

It is the responsibility of each Statement Recipient to notify ERCOT if a Settlement Statement for the RTM is not available on the MIS Certified Area on the date specified for posting of that Settlement Statement in the Settlement Calendar. Each Settlement Statement for the RTM is deemed to have been available on the posting date specified on the Settlement Calendar, unless it notifies ERCOT to the contrary. If ERCOT receives notice that a Settlement Statement is not available, ERCOT shall make reasonable attempts to provide the Settlement Statement to the Statement Recipient, and ERCOT shall modify the Settlement and billing timeline accordingly for that Settlement Statement.

9.5.11 Validation of the True-Up Statement for the Real-Time Market

The Statement Recipient is considered to have validated each RTM True-Up Statement unless it has filed a Settlement and billing dispute or reported an exception within ten Business Days after the RTM True-Up Statement has been posted on the MIS Certified Area.

9.5.12 Suspension of Issuing Settlement Statements for the Real-Time Market

The Board may direct ERCOT to suspend the issuance of any Settlement Statement for the RTM to address unusual circumstances. Any proposal to suspend settlements must be presented to TAC for review and comment, in a reasonable manner under the circumstances, before such suspension.

9.6 Settlement Invoices for the Real-Time Market

(1) ERCOT shall prepare Settlement Invoices for the RTM (RTM Invoices) on a net basis for each Invoice cycle based on RTM Initial Statements, RTM Final Statements, RTM True-Up Statements and RTM Resettlement Statements. ERCOT must issue Invoices on a weekly basis on each Thursday, unless that Thursday is not a Business Day. If a Thursday is not a Business Day, ERCOT shall issue the RTM Invoices on the next Business Day after that Thursday. ERCOT will post the actual dates that it will issue RTM Invoices under Section 9.1.2. For each cycle, the Market Participant to whom the RTM Invoice is addressed (“Invoice Recipient”) is either a net payee or net payor.

(2) Each Invoice Recipient shall pay any net debit and be entitled to receive any net credit shown on the RTM Invoice on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit or credit.

(3) ERCOT shall post RTM Invoices on the MIS Certified Area. The Invoice Recipient is responsible for accessing the RTM Invoice on the MIS Certified Area once posted by ERCOT.

(4) RTM Invoice items must be grouped by Initial, Final, Resettlement, and True-Up categories and must be sorted by Operating Day within each category. RTM Invoices must contain the following information:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due/Payable – the aggregate summary of all charges owed or due by the Invoice Recipient summarized by Operating Day;

(d) Time Periods – the time period covered for each line item;

(e) Run Date – the date on which the Invoice was created and published;

(f) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes;

(g) Statement Reference – an identification code used to reference each Settlement Statement invoiced;

(h) Payment Date – the date and time that Invoice amounts are to be paid or received;

(i) Remittance Information Details – details including the account number, bank name and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due; and

(j) Overdue Terms – the terms that would be applied if payments were received late.

9.7 Payment Process for the RTM

Payments for the RTM are due on a Business Day and Bank Business Day basis in a two-day, two-step process as detailed below.

9.7.1 Invoice Recipient Payment to ERCOT for the RTM

(1) The payment due date and time for the RTM Invoice, with funds owed by an Invoice Recipient, is 1700 on the fifth Bank Business Day after the RTM Invoice date, unless the fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All RTM Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars by either of the following:

(a) On or before the payment due date if the payment is made by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal); or

(b) On or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House (ACH) funds.

9.7.2 ERCOT Payment to Invoice Recipients for the Real-Time Market

(1) Subject to the availability of funds as discussed in paragraph (2) below, ERCOT must pay RTM Invoices with funds owed to an Invoice Recipient by 1700 on the next Bank Business Day after payments are due for that RTM under Section 9.7.1, Invoice Recipient Payment to ERCOT for the RTM, subject to ERCOT's right to withhold payments for any reason set forth in these Protocols or as a matter of law, unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit to each Invoice Recipient for same day value the amounts determined by ERCOT to be available for payment to that Invoice Recipient under paragraph (d) of Section 9.7.3.

9.7.3 Partial Payments by Invoice Recipients for the RTM

If at least one Invoice Recipient owing funds does not pay its RTM Invoice in full (*i.e.* a short-pay), ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient before ERCOT makes any payments for that RTM to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available security pledged to ERCOT by each short-paying Invoice Recipient that did not pay the amount due under paragraph (a) above.

(c) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT to a short-paying Invoice Recipient against amounts not paid by that Invoice Recipient, and ERCOT shall apply the amount offset or recouped to cover short pays by that Invoice Recipient.

(d) If, after taking the actions set forth in paragraph (a), (b) and (c), above, ERCOT still does not have sufficient funds to pay in full all amounts owed to RTM Invoice Recipients, ERCOT shall deduct any applicable RTM administrative fees as specified in Section 9.16 and payments for RMR Services from the amount received or collected and reduce payments to all RTM Invoice Recipients owed monies from ERCOT except for monies owed for RMR Services. The reductions must be based on a pro rata basis of monies owed to each RTM Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short pays and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the RTM Invoice.

(e) One hundred eighty days following a short-pay of a RTM Invoice, if sufficient funds continue to be unavailable for ERCOT to pay all amounts in full (excluding late fees) to short-paid Entities for that RTM Invoice, and the short-paying Entity is not complying with a payment plan designed to enable ERCOT to pay all amounts in full (excluding late fees) to short-paid Entities, the following shall occur:

(i) ERCOT will cease charging late fees to the short-paying Entity; provided however, that ERCOT may cease charging late fees earlier than 180 days following a short-payment of a RTM Invoice if ERCOT, in its sole discretion, determines that the recovery of late fees from the short-paying Entity is unlikely; and

(ii) ERCOT shall uplift short-paid amounts through the RTM Uplift process described below in Sections 9.7.3.1, RTM Uplift Invoices and Section 9.7.3.2, Payment Process for RTM Uplift Invoices.

(f) When ERCOT enters into a payment plan with a short-pay Invoice Recipient, ERCOT shall post to the MIS Secure Area:

(i) The short-pay plan;

(ii) The schedule of quantifiable expected payments, updated if and when modifications are made to the payment schedule; and

(iii) Invoice dates to which the payments will be applied.

(g) To the extent ERCOT is able subsequently to collect past due funds owed by a short-paying Invoice Recipient, ERCOT shall allocate the collected funds to the earliest RTM Invoice for which that Invoice Recipient remains a short-payer. ERCOT shall use its best efforts to distribute collected past due funds on a pro rata basis of monies owed on the next Business Day that is also a Bank Business

Day after receipt of the monies, when sufficient funds for the applicable Operating Day are available in this Settlement process.

9.7.3.1 RTM Uplift Invoices

(1) ERCOT shall collect the total short-pay amount of an RTM Invoice, less the total payments expected from a payment plan from the QSEs representing LSEs. The amount charged to each QSE is determined using the Load Ratio Share for the calendar month three months before the date on which ERCOT issues the RTM Uplift Invoice. ERCOT must pay the funds it collects from payments on RTM Uplift Invoices to the Entities previously short-paid. ERCOT shall notify those Entities of the details of the payment.

(2) Any Uplifted short-paid amount greater than $2,500,000 must be scheduled so that no amount greater than $2,500,000 is charged on each set of RTM Uplift Invoices until ERCOT Uplifts the total short-paid amount. ERCOT must issue RTM Uplift Invoices at least 30 days apart from each other.

(3) ERCOT shall issue RTM Uplift Invoices no earlier than 180 days following a short-pay of a RTM Invoice on the date specified in the Settlement Calendar. The Invoice Recipient is responsible for accessing the Invoice on the MIS Certified Area once posted by ERCOT.

(4) Each RTM Uplift Invoice must contain:

(a) The Invoice Recipient’s name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due or Payable – the aggregate summary of all charges owed by an RTM Uplift Invoice Recipient;

(d) Run Date – the date on which ERCOT created and published the RTM Uplift Invoice;

(e) Invoice Reference Number – a unique number generated by the ERCOT applications for payment tracking purposes;

(f) Uplift Invoice Reference – an identification code used to reference the RTM amount Uplifted;

(g) Payment Date and Time – the date and time that RTM Uplift Invoice amounts must be paid;

(h) Remittance Information Details – details including the account number, bank name, and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient’s account from which ERCOT may draw payments due; and

(i) Overdue Terms – the terms that would apply if the Market Participant makes a late payment.

(5) Each Invoice Recipient shall pay any net debit shown on the RTM Uplift Invoice on the payment due date whether or not there is any Settlement and Billing dispute regarding the amount of the debit.

9.7.3.2 Payment Process for RTM Uplift Invoices

Payments for the RTM are due on a Bank Business Day and Business Day basis in a two-day, two-step process as detailed below.

9.7.3.2.1 Invoice Recipient Payment to ERCOT for RTM Uplift

(1) The payment due date and time for the RTM Uplift Invoice with funds owed by an Invoice Recipient is 1700 on the fifth Bank Business Day after the RTM Uplift Invoice date, unless fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All RTM Uplift Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. dollars by either of the following:

(a) On or before the payment due date if the payment is made by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal); or

(b) On or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House (ACH) funds.

9.7.3.2.2 ERCOT Payment to Invoice Recipients for RTM Uplift

(1) Subject to the availability of funds as discussed in paragraph (2) below, uplifted funds received from RTM Uplift Invoices must be paid by ERCOT to short-paid Invoice Recipients by 1700 on the next Bank Business Day after payments are due for that RTM Uplift Invoice under Section 9.7.3.2.1, Invoice Recipient Payment to ERCOT for RTM Uplift, subject to ERCOT's right to withhold payments under Section 16, or pursuant to common law unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit to each short-paid Invoice Recipient for same day value the amounts determined by ERCOT to be available for payment to that short-paid Invoice Recipient under paragraph (d) of Section 9.7.3.

(3) Any short and late payments of RTM Uplift Invoices must be handled under Section 9.7.3 and Section 9.7.5 respectively.

9.7.4 Enforcing the Security of a Short-Paying Invoice Recipient

ERCOT shall make reasonable efforts to enforce the security of the short-paying Invoice Recipient (pursuant to Section 16.11.6) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its security under Section 16.

9.7.5 Late Fees and Late Fee Invoices for the RTM

(1) A short-paying Invoice Recipient shall pay late fees to ERCOT on the short-pay amount according to the late fee terms specified in the ERCOT fee schedule posted on the MIS Public Area for the period from and including the relevant payment due date to the date on which the payment, including any related transaction costs incurred by ERCOT, is received by ERCOT. ERCOT will cease charging late fees to the defaulting Entity when the conditions described in item (e) of Section 9.7.3 are met.

(2) ERCOT shall distribute on a pro rata basis of monies owed to each Invoice Recipient any RTM late fee revenues, less ERCOT's transaction costs, to the unpaid RTM Invoice Recipients.

(3) ERCOT shall post to the MIS Certified Area for each RTM Invoice Recipient, an Invoice based on late fees (RTM Late Fee Invoice). The RTM Late Fee Invoice Recipient is responsible for accessing the information from the MIS Certified Area once posted by ERCOT.

(4) ERCOT shall issue RTM Late Fee Invoices on the tenth day after the end of the month, unless the tenth day is not a Business Day. If that tenth day is not a Business Day, ERCOT shall issue the RTM Late Fee Invoice by 2400 of the next Business Day thereafter. The actual dates that RTM Late Fee Invoices will be issued will be posted by ERCOT under Section 9.1.2.

(5) Each RTM Late Fee Invoice must contain:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due or Payable – the aggregate summary of all charges owed to or due from an Invoice Recipient;

(d) Time Periods – the time period covered for each line item;

(e) Run Date – the date on which ERCOT created and published the Invoice;

(f) Invoice Reference Number – a unique number generated by the ERCOT applications for payment tracking purposes;

(g) Payment Date and Time – the date and time that Invoice amounts are to be paid or received;

(h) Remittance Information Details – details, including the account number, bank name and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due; and

(i) Overdue Terms – the terms that would be applied if payments were received late.

(6) Payments for RTM Late Fee Invoices must be made on days that are both a Business Day and a Bank Business Day in a two-day, two-step process as detailed below. Payments for RTM Late Fee Invoices are due on the applicable payment due date, whether or not there is any Settlement and Billing dispute regarding the amount of the payment.

(a) The payment due date and time for the RTM Late Fee Invoice, with funds owed by an Invoice Recipient, is 1700 on the fourth Business Day after the RTM Late Fee Invoice date unless that day is not a Bank Business Day. If the fourth Business Day is not a Bank Business Day, then the payment is due by 1700 on the next Business Day after the fourth Business Day that is also a Bank Business Day.

(b) All RTM Late Fee Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars by either of the following:

(i) On or before the payment due date if the payment is made by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal); or

(ii) On or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House (ACH) funds.

(c) Subject to the availability of funds as discussed in paragraph (d) below, RTM Late Fee Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next Bank Business Day after payments are due for that RTM Late Fee Invoice under paragraph (a) above, subject to ERCOT's right to withhold payments under Section 16 or pursuant to common law unless that next Bank Business Day is not a Business Day. If that next Bank Business Day is not a Business Day, then the payment is due on the next Bank Business Day thereafter that is also a Business Day.

(d) If at least one Invoice Recipient owing funds does not pay its RTM Late Fee Invoice in full (short-pays), ERCOT shall reduce payments to all RTM Late Fee Invoice Recipients owed monies from ERCOT. The reductions must be based on a pro rata basis of monies owed to each Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short pay and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the Invoice. ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit to each Invoice Recipient for same day value the amounts determined by ERCOT to be available for payment.

9.8 CRR Auction Award Invoices

(1) ERCOT shall prepare invoices for each CRR Auction (CRR Auction Invoice) on a net basis. Invoices must be issued on the first Business Day following the completion of a CRR Auction on the date specified in the Settlement Calendar. For each CRR Auction Invoice, the CRR Account Holder to whom the Invoice is addressed ("Invoice Recipient") is either a net payee or net payor. The Invoice Recipient is responsible for accessing the CRR Auction Invoice on the MIS Certified Area once posted by ERCOT.

(2) Each Invoice Recipient shall pay any net debit and be entitled to receive any net credit shown on the CRR Auction Invoice on the payment due date. Payments for CRR Auction Invoices are due on the applicable payment due date, whether or not there is any Settlement and Billing dispute regarding the amount of the payment.

(3) ERCOT shall post on the MIS Certified Area for each Invoice Recipient a CRR Auction Invoice based on CRR Auction charges and payments as set forth in:

(a) Section 7.5.6.1, Payment of an Awarded CRR Auction Offer;

(b) Section 7.5.6.2, Charge of an Awarded CRR Auction Bid; and

(c) Section 7.5.6.3, Charge of PCRRs Pertaining to a CRR Auction.

(4) CRR Auction Invoices must contain the following information:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due/Payable – the aggregate summary of all charges owed to or due from the Invoice Recipient summarized by CRR Auction;

(d) Time Period – the CRR Auction for which the Invoice is generated;

(e) Run Date – the date on which ERCOT created and published the Invoice;

(f) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes;

(g) Product Description – a description of each product awarded in, sold in, or allocated before the CRR Auction;

(h) Payment Date – the date and time that Invoice amounts are to be paid or received; and

(i) Remittance Information Details – details including the account number, bank name and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due.

9.9 Payment Process for CRR Auction Invoices

Payments for the CRR Auction are due on a Business Day and Bank Business Day basis in a two-day, two-step process as detailed below.

9.9.1 Invoice Recipient Payment to ERCOT for the CRR Auction

(1) The payment due date and time for the CRR Auction Invoice, with funds owed by an Invoice Recipient, is 1700 on the third Bank Business Day after the CRR Auction Invoice date, unless third Bank Business Day is not a Business Day. If the third Bank Business Day is not a Business Day, the payment is due by 1700 on the next Bank Business Day after the third Bank Business Day that is also a Business Day.

(2) All CRR Auction Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars by either of the following:

(a) On or before the payment due date if the payment is made by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal); or

(b) On or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House (ACH) funds.

(3) All CRR Auction Invoices must be paid in full on the Invoice due date. In the event of a partial payment:

(a) CRR Bids awarded and PCRRs allocated to the Invoice Recipient will be forfeited, and

(b) CRR Offers awarded to the Invoice Recipient will be honored.

9.9.2 ERCOT Payment to Invoice Recipients for the CRR Auction

(1) CRR Auction Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next day that is both a Business Day and a Bank Business Day after the day that payments are due for that CRR Auction Invoice under Section 9.9.1, Invoice Recipient Payment to ERCOT for the CRR Auction, subject to ERCOT's right to withhold payments under Section 16 or pursuant to the common law.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each Invoice Recipient for same day value the amounts owed to each Invoice Recipient.

9.9.3 Enforcing the Security of a Short-Paying CRR Auction Invoice Recipient

ERCOT shall make reasonable efforts to enforce the security of the short-paying Invoice Recipient (pursuant to Section 16.11.6) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its security under Section 16.

9.10 CRR Auction Revenue Distribution Invoices

(1) ERCOT shall prepare Settlement Invoices for CRR Auction Revenue Distribution (CARD Invoices) on a monthly basis on the first Business Day following the RTM Initial Settlement posting of the last day of the month on the date specified in the Settlement Calendar.

(2) ERCOT shall true up the distribution of monthly CRR Auction Revenues by posting additional Settlement Invoices on the first Business Day following the RTM Final Settlement posting of the last day of the month on the date specified in the Settlement Calendar. A trued up CARD Invoice will reflect differences to financial records generated on the previous CARD Invoice for a given month.

(3) For each cycle, the Market Participant to whom the CARD Invoice is addressed ("Invoice Recipient") is either a payee or payor. The Invoice Recipient is responsible for accessing the CARD Invoice on the MIS Certified Area once posted by ERCOT.

(4) Each Invoice Recipient shall pay any debit and be entitled to receive any credit shown on the CARD Invoice on the payment due date. Payments for CARD Invoices are due on the applicable payment due date whether or not there is any Settlement and Billing dispute regarding the amount of the payment.

(5) ERCOT shall post on the MIS Certified Area for each Invoice Recipient a CARD Invoice based the calculations located:

(a) Section 7.5.6.4, CRR Auction Revenues; and

(b) Section 7.5.7, Method for Distributing CRR Auction Revenues.

(6) CARD Invoices must contain the following information:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Due/Payable – the aggregate summary of all charges owed to or due from the Invoice Recipient summarized by CRR Auction Revenue month;

(d) Time Period – the CRR Auction Revenue month for which the Invoice is generated, including Initial or Final distribution;

(e) Run Date – the date on which ERCOT created and published the Invoice;

(f) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes;

(g) Payment Date – the date and time that Invoice amounts are to be paid or received; and

(h) Remittance Information Details – details including the account number, bank name and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due.

9.11 Payment Process for CRR Auction Revenue Distribution

Payments for CARD Invoices are due on a Business Day and Bank Business Day basis in a two-day, two-step process as detailed below.

9.11.1 Invoice Recipient Payment to ERCOT for CRR Auction Revenue Distribution

(1) The payment due date and time for the CARD Invoice, with funds owed by an Invoice Recipient, is 1700 on the fifth Bank Business Day after the CARD Invoice date, unless the fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All CARD Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars by either of the following:

(a) On or before the payment due date if the payment is made by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal); or

(b) On or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House (ACH) funds.

9.11.2 ERCOT Payment to Invoice Recipients for CRR Auction Revenue Distribution

(1) CARD Invoices with funds owed to an Invoice Recipient must be paid by ERCOT to the Invoice Recipient by 1700 on the next day that is both a Business Day and a Bank Business Day after the day that payments are due for that CARD Invoice under Section 9.11.1, Invoice Recipient Payment to ERCOT for CRR Auction Revenue Distribution, subject to ERCOT's right to withhold payments under Section 16 and pursuant to common law.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each Invoice Recipient for same day value, the amounts owed to each Invoice Recipient.

9.11.3 Partial Payments by Invoice Recipients for CRR Auction Revenue Distribution

If at least one Invoice Recipient owing funds does not pay its CARD Invoice in full (short-pay), ERCOT shall follow the procedure set forth below:

(a) ERCOT shall make every reasonable attempt to collect payment from each short-paying Invoice Recipient before any payments owed by ERCOT for that month's distribution of CRR Auction Revenues is due to be paid to applicable Invoice Recipient(s).

(b) ERCOT shall draw on any available security pledged to ERCOT by each short-paying Invoice Recipient that did not pay the amount due under paragraph (a) above.

(c) ERCOT shall offset or recoup any amounts owed, or to be owed, by ERCOT to a short-paying Invoice Recipient against amounts not paid by that Invoice Recipient and ERCOT shall apply the amount offset or recouped to cover payment shortages by that Invoice Recipient.

(d) If, after taking the actions set forth in paragraph (a), (b) and (c), above, ERCOT still does not have sufficient funds to pay all amounts that it owes to CARD Invoice Recipients in full, ERCOT shall reduce payments to all CARD Invoice Recipients owed monies from ERCOT. The reductions shall be based on a pro rata basis of monies owed to each CARD Invoice Recipient, to the extent necessary to clear ERCOT's accounts on the payment due date to achieve revenue neutrality for ERCOT. ERCOT shall provide to all Market Participants payment details on all short payments and subsequent reimbursements of short pays. Details must include the identity of each short-paying Invoice Recipient and the dollar amount attributable to that Invoice Recipient, broken down by Invoice numbers. In addition, ERCOT shall provide the aggregate total of all amounts due to all Invoice Recipients before applying the amount not paid on the CARD Invoice.

9.11.4 Enforcing the Security of a Short-Paying CARD Invoice Recipient

ERCOT shall make reasonable efforts to enforce the security of the short-paying Invoice Recipient (pursuant to Section 16.11.6) to the extent necessary to cover the short-pay. A short-paying Invoice Recipient shall restore the level of its security under Section 16.

9.12 CRR Balancing Account Invoices

(1) ERCOT shall prepare Settlement Invoices for the CRR Balancing Account on a monthly basis on the first Business Day following the RTM Initial Settlement posting of the last day of the month on the date specified in the Settlement Calendar.

(2) For each Invoice cycle, the Market Participant to whom the CRR Balancing Account Invoice is addressed ("Invoice Recipient") is a payee. The Invoice Recipient is responsible for accessing the CRR Balancing Account Invoice on the MIS Certified Area once posted by ERCOT.

(3) Each Invoice Recipient shall be entitled to receive any credit shown on the CRR Balancing Account Invoice on the payment due date.

(4) ERCOT shall post on the MIS Certified Area for each Invoice Recipient a CRR Balancing Account Invoice based the calculations located:

- (a) Section 7.9.3.4, Monthly Refunds to Short-Paid CRR Owners; and
- (b) Section 7.9.3.5, CRR Balancing Account Closure.

(5) CRR Balancing Account Invoices must contain the following information:

- (a) The Invoice Recipient's name;
- (b) The ERCOT identifier (Settlement identification number issued by ERCOT);
- (c) Net Amount Payable – the aggregate summary of all amounts owed to the Invoice Recipient summarized by month;
- (d) Time Period – the time period covered for each line item;
- (e) Run Date – the date on which the ERCOT created and published Invoice;
- (f) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes; and
- (g) Payment Date – the date and time that Invoice amounts are to be received.

9.13 Payment Process for the CRR Balancing Account

Payments for the CRR Balancing Account are due on a Business Day and Bank Business Day basis in a one-day, one-step process, as detailed below.

(1) By 1700 on the first day that is both a Business Day and a Bank Business Day following the due date of the RTM Invoice that includes the RTM Initial Settlement statement for the last day of the month and subject to ERCOT's right to withhold payments under Section 16 and pursuant to common law ERCOT shall pay:

(a) To each short-paid CRR Owner a monthly refund from the positive balance in the CRR Balancing Account, with the amount paid to each CRR Owner as calculated in Section 7.9.3.4; and

(b) To each QSE, any remaining positive balance in the CRR Balancing Account, with the amount paid to each QSE as calculated in Section 7.9.3.5.

(2) ERCOT shall give irrevocable instructions to the ERCOT financial institution to remit, to each CRR Owner or QSE, for same day value, the amounts determined by ERCOT to be available for payment.

9.14 Settlement and Billing Dispute Process

9.14.1 Data Review, Validation, Confirmation, and Dispute of Settlement Statements

Statement Recipients and Invoice Recipients for the Day-Ahead Market (DAM) and Real-Time Market (RTM) are responsible for reviewing their Settlement Statements and Settlement Invoices to verify the accuracy of the data used to produce them. Statement Recipients and Invoice Recipients must submit any dispute related to a Settlement Statement or Settlement Invoice pursuant to this Section.

9.14.2 Notice of Dispute

(1) A Settlement Statement Recipient may dispute items or calculations in the most recently issued Settlement Statement for an Operating Day, except as limited for RTM True-Up Statements in paragraph (3) below. The dispute will apply to the Operating Day in question, not to the associated Settlement Statement. The Market Participant must enter the Settlement and billing dispute electronically through the ERCOT dispute tool provided on the Market Information System (MIS) Certified Area. In processing disputes under this Section, ERCOT will analyze the latest Settlement Statement issued.

(2) An Invoice Recipient may dispute elements of an Invoice that are not the result of a Settlement Statement that are contained on the Invoice. The Invoice Recipient must file the RTM Invoice dispute within ten Business Days of the date on which ERCOT posted the Invoice.

(3) The Statement Recipient is deemed to have validated each RTM True-Up Statement or Resettlement Statement arising from the True-Up Statement unless it has raised a Settlement and billing dispute or reported an exception within ten Business Days of the date on which ERCOT issued the Settlement Statement. With respect to an RTM True-Up Statement or any subsequent Resettlement Statement after ERCOT issued the True-Up Statement, ERCOT will consider only Settlement and billing disputes associated with incremental changes between the RTM True-Up Statement or Resettlement Statement, and the most recent previous Settlement Statement for that Operating Day. The Statement Recipient may recover only the amounts associated with the incremental monetary change between the prior Statement and the Statement from which the dispute arose. ERCOT shall reject late-filed Settlement and billing disputes. Once the deadline for filing a dispute has passed, an RTM True-Up Statement binds the Statement Recipient to which it relates unless ERCOT issues a subsequent Resettlement Statement pursuant to this Section. Once the deadline for filing a dispute has passed, an RTM Statement binds the Statement Recipient to which it relates unless ERCOT issues a subsequent Resettlement Statement.

(4) The Statement Recipient is deemed to have validated each DAM Settlement or Resettlement Statement unless it has raised a Settlement and billing dispute or reported an exception within ten Business Days of the date on which ERCOT issued the Settlement or Resettlement Statement. With respect to a DAM Resettlement Statement, ERCOT will consider only Settlement and billing disputes associated with incremental changes between the DAM Resettlement Statement and the most recent previous Settlement Statement for that Operating Day. The Statement Recipient may recover only the amounts associated with the incremental monetary change between the prior Statement and the Statement from which the dispute arose. ERCOT shall reject late-filed Settlement and billing disputes. Once the deadline for filing a dispute has passed, a DAM Statement binds the Statement Recipient to which it relates unless ERCOT issues a subsequent Resettlement Statement.

(5) ERCOT shall reject Settlement and billing disputes for a given Operating Day during the 20 Business Days before the scheduled date for issuance of the RTM True-Up Statement for that Operating Day.

(6) However, to the extent a disputing party claims that the Settlement or billing dispute relates to information made available under Section 1.3.3, Expiration of Confidentiality, the disputing party must register the Settlement and billing dispute with ERCOT by electronic means within 60 days after the date the information became available. All communication to and from ERCOT concerning disputes must be made through either the MIS Certified Area or other electronic communication.

9.14.3 Contents of Notice

(1) ERCOT shall reject a dispute that does not contain the items listed in this Section.

(2) ERCOT shall provide automatic field population techniques or drop-down boxes for appropriate data elements below. The notice of Settlement and billing dispute must state clearly:

(a) Disputing Entity;

(b) Dispute contact person(s);

(c) Dispute contact information;

(d) Operating Day in dispute;

(e) Statement type;

(f) Charge Type;

(g) Time period in dispute;

(h) Amount in dispute;

(i) Settlement and billing dispute type; and

(j) Reasons for the dispute.

(3) Each Settlement and billing dispute must specify an Operating Day and a Charge Type. If a condition causing a dispute affects multiple Operating Days or Charge Types, a Settlement Statement or Invoice Recipient may file a dispute form for each Charge Type for one or more Operating Days affected on a single dispute that are all in the same calendar month.

(4) A Settlement Statement or Invoice Recipient may pursue the dispute through any process provided by ERCOT for resolving differences in Settlement determinants.

(5) Forms for entering a Settlement and billing dispute must be provided on the MIS Certified Area.

(6) The Market Participant must submit the Settlement and billing dispute to ERCOT with sufficient evidence to support the claim.

(7) The Market Participant must submit a dispute using an ERCOT-approved electronic format. ERCOT shall provide a dispute tracking identifier to the Statement Recipient or Invoice Recipient.

9.14.4 ERCOT Processing of Disputes

(1) ERCOT shall process disputes in accordance with this Section, Section 9.14.2, Notice of Dispute, and the required data in Section 9.14.3, Contents of Notice.

(2) If ERCOT requires additional data to resolve the dispute, ERCOT shall send the Statement or Invoice Recipient a list of the required additional data within seven Business Days of the date the dispute was filed. The Statement or Invoice Recipient shall respond with the entire set of required data within five Business Days of ERCOT's request or by a date agreed upon by ERCOT and the Market Participant that is no later than eight Business Days prior to the posting of the True-Up Settlement Statement for the disputed Operating Day. If ERCOT does not receive the data within that time frame, ERCOT shall deny the dispute.

(3) On each Business Day, ERCOT shall issue an aggregated Settlement and Billing dispute resolution report on the MIS Secure Area containing information related to all disputes that are not yet closed or that have been closed recently. Additionally, on each Business Day and for each Statement or Invoice Recipient, ERCOT shall issue a report on the MIS Certified Area containing details about each dispute that is not yet closed or that has been closed recently.

(4) ERCOT shall make all reasonable attempts to complete all RTM Settlement and Billing disputes submitted within 15 Business Days of the issuance of the RTM Initial Statement in time for inclusion on the RTM Final Statement for the relevant Operating Day.

(5) All complete disputes of the DAM received within ten Business Days after ERCOT posts that day's DAM Settlement Statement will be included in a Resettlement of the DAM Operating Day under Section 9.2.5, DAM Resettlement Statement.

(6) For Settlement and billing disputes requiring complex research or additional time for resolution, ERCOT shall notify the Invoice Recipient or Statement Recipient of the length of time expected to research and resolve those disputes and, if ERCOT grants a portion or all of the dispute, ERCOT shall post the necessary adjustments on the next available Settlement Statement for the Operating Day.

(7) Statement or Invoice Recipients have the right to proceed to the Alternative Dispute Resolution (ADR) process in Section 20, Alternative Dispute Resolution Procedure, for filed disputes that cannot be resolved through the Settlement and billing dispute process outlined in Section 9.14, Settlement and Billing Dispute Process.

9.14.4.1 Status of Dispute

ERCOT will assign a status to each dispute as defined in the following Sections.

9.14.4.1.1 Not Started

The status of a Settlement and billing dispute will initially be set to "Not Started" when the Market Participant enters the dispute into the ERCOT dispute resolution system.

9.14.4.1.2 Open

The status of a Settlement and billing dispute is set to "Open" when the Settlement Statement or Invoice Recipient submits a dispute to ERCOT and ERCOT begins the resolution process.

9.14.4.1.3 Closed

When the status is set to "Closed," no updates or additions are permitted to the dispute record. The status of the dispute is "Closed" when one of the following conditions occurs:

(1) If, after 45 days from receiving notice of a denied dispute, the Settlement Statement or Invoice Recipient does not begin the ADR process, ERCOT will close the dispute.

(2) If ERCOT grants a Settlement and billing dispute, ERCOT will close the dispute no sooner than when the necessary adjustments appear on the next available Settlement Statement.

(3) If ERCOT grants a dispute with exceptions, ERCOT will close the dispute no sooner than when the necessary adjustments for the granted portion appear on the next available Settlement Statement. If the Settlement Statement Recipient or Invoice Recipient disagrees with ERCOT's exceptions, ERCOT will close dispute upon completion of further investigation and resolution in accordance with Section 9.14.4.2.3, Granted with Exceptions.

9.14.4.1.4 Withdrawn

A Market Participant who submitted a Settlement and billing dispute may withdraw that dispute at any time. If withdrawal occurs, the Dispute status is set to "Withdrawn" and any research and resolution activities on that dispute will cease.

9.14.4.1.5 ADR

A Settlement and billing dispute status will be set to "ADR" if the Market Participant enters the ADR process as the result of the dispute. The dispute will remain in the ADR status as long as the Market Participant has an active ADR. At the end of the ADR process, ERCOT will set the dispute status to "Closed".

9.14.4.2 Resolution of Dispute

Each resolved dispute will have a resolution as defined in the following Sections.

9.14.4.2.1 Denied

(1) ERCOT shall reject a Settlement and billing dispute determined by ERCOT to be missing required information as defined in Section 9.8.3, Contents of Notice, and provide the Settlement Statement or Invoice Recipient an explanation of the missing data. ERCOT shall provide specific Protocol language supporting the reasons that data provided by the Settlement Statement or Invoice Recipient is insufficient. If able to do so timely, an Invoice Recipient or Settlement Statement Recipient may resubmit the dispute with additional information under Section 9.8.2, Notice of Dispute. Once the Statement or Invoice Recipient submits the required information and ERCOT determines the Settlement and billing dispute is timely and complete, the dispute status is “Open”.

(2) If ERCOT concludes that the Settlement Statement or Invoice is correct, ERCOT shall deny the Settlement and billing dispute. ERCOT shall notify the Settlement Statement or Invoice Recipient when it denies a Settlement and billing dispute and provide the Statement or Invoice Recipient the reasons and supporting data for the denial, while maintaining the confidentiality of Protected Information.

(3) If the Settlement Statement or Invoice Recipient is not satisfied with the outcome of a denied Settlement and billing dispute, the Settlement Statement or Invoice Recipient may proceed to ADR as described in Section 20.

9.14.4.2.2 Granted

When ERCOT determines that the disputed Settlement Statement or Invoice are in error as alleged in the Settlement and billing dispute, ERCOT shall grant the Settlement and billing dispute and notify the Settlement Statement or Invoice Recipient of the resolution and provide it the reasons and supporting data for resolution, while maintaining the confidentiality of Protected Information. ERCOT shall notify all other Settlement Statement or Invoice Recipients of the financial impact of granted disputes. Upon resolution of the issue, ERCOT shall process the dispute’s resolution on the next available Settlement Statement for the affected Operating Day.

9.14.4.2.3 Granted with Exceptions

(1) ERCOT may determine that a Settlement and billing dispute is “Granted with Exceptions” when ERCOT deems the basis for the Settlement and billing dispute partially correct. ERCOT shall provide the exception information to the Settlement Statement or Invoice Recipient. ERCOT shall notify the Settlement Statement or Invoice Recipient of the “Granted with Exceptions” resolution and shall provide the reasons and supporting data, while maintaining the confidentiality of Protected Information for the resolution. ERCOT shall notify all other Qualified Scheduling Entities (QSEs) of the financial impact of “Granted with Exceptions” disputes and which Invoices are affected. The Settlement Statement or Invoice Recipient of the dispute granted with exceptions shall acknowledge receipt of the notice within ten Business Days after ERCOT publishes the resolution as “Granted with Exceptions”. The acknowledgement must indicate acceptance or rejection of the documented exceptions to the granting of the dispute. If

the Settlement Statement or Invoice Recipient does not timely reject the dispute outcome, it shall be deemed accepted. If the Market Participant accepts the exceptions, ERCOT shall post the necessary adjustments on the next available Settlement Statement for the affected Operating Day.

(2) If a Settlement Invoice or Statement Recipient rejects the outcome of a dispute "Granted with Exceptions," ERCOT must investigate the dispute further. ERCOT must include the granted portion of the dispute on the next Settlement Statement for the affected Operating Day and notify all other Settlement Statement or Invoice Recipients of the financial impact of the granted portion of the dispute. After further investigation, if ERCOT subsequently grants the Settlement and billing dispute, ERCOT must process the dispute on the next available Settlement Statement for the affected Operating Day. ERCOT shall notify all other Settlement Statement or Invoice Recipients of the financial impact of the granted portion of the dispute. If exceptions to the dispute still exist, the Settlement Statement or Invoice Recipient may either accept the dispute for resolution as "Granted with Exceptions" or begin ADR according to Section 20, Alternative Dispute Resolution Procedure.

9.14.4.3 Closed

(1) If, after 45 days from receiving notice of a denied dispute, the Settlement Statement or Invoice Recipient does not begin ADR, ERCOT will close the dispute.

(2) After ERCOT grants the Settlement and billing dispute and the necessary adjustments appear on the next available Settlement Statement, ERCOT will close the Settlement and billing dispute.

(3) If the Settlement Statement or Invoice Recipient accepts ERCOT's exceptions when it deems a dispute granted with exceptions, ERCOT shall post the necessary adjustments on the next available Settlement Statement for the Operating Day and shall change the dispute status to closed. ERCOT shall close the dispute unless it receives notice from the Settlement Statement or Invoice Recipient regarding the exceptions within ten Business Days of the granted with exceptions notice.

9.14.5 Resettlement of Emergency Interruptible Load Service (EILS)

ERCOT shall issue a Resettlement Statement for the EILS Contract Period for any approved EILS disputes no later than 120 calendar days after the date that the EILS Contract Period was initially settled. All disputes for an EILS Contract Period will be due 60 calendar days after the date that the EILS Contract Period was initially settled.

9.14.6 Disputes for Operations Decisions

Settlement Statement or Invoice Recipients may not dispute a Settlement Statement or Invoice due to a decision made by ERCOT in its operation of the ERCOT System, unless the Market

Participant alleged the decision violated these Protocols. Inquiries or disputes concerning such decisions, Protocols, or Operating Guides must be handled through the Protocol change process set forth in Section 21.

9.15 Settlement Charges

The calculations to be used for Settlement charges are contained in Section 4, Day-Ahead Operations, Section 5, Transmission Security Analysis and Reliability Unit Commitment, Section 6, Adjustment Period and Real-Time Operations, Section 7, Congestion Revenue Rights, and Section 9, Settlement and Billing.

9.15.1 Charge Type Matrix

ERCOT shall post a Charge Type Matrix on the MIS Public Area that summarizes each Charge Type by variable name used in the Protocols, description, and Protocol section number reference. ERCOT post changes to this Charge Type matrix at least ten days before implementation of change.

9.16 Administrative Fees

The ERCOT Board shall determine, subject to PUCT approval, the administrative fees, as described in this Section 9.16 and ERCOT shall post them on the MIS Public Area within two Business Days following PUCT approval.

9.16.1 ERCOT System Administration Charge

Each QSE shall pay an ERCOT System Administration Charge to administer the RTM market. The ERCOT System Administration Charge is for each 15-minute Settlement Interval for each QSE.

$$\mathbf{ESACAMT}_{q} = \mathbf{LAFF} * \sum_{p} \mathbf{RTAML}_{q,\,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
ESACAMT $_{q}$	**$**	***ERCOT System Administration Charge***—The ERCOT System Administration Charge for each QSE per 15-minute Settlement Interval.
RTAML $_{q,\,p}$	**MWh**	*Real-Time Adjusted Metered Load*— The sum of the Adjusted Metered Load at the Electrical Buses included in Settlement Point *p*, represented by QSE *q*, for the 15-minute Settlement Interval.
LAFF	**$/MWh**	***Load Administration Fee Factor***—The ERCOT System administration fee rate in dollars per MWh.

Variable	Unit	Definition
q	***none***	*A QSE*
p	***none***	*A Settlement Point*

9.16.2 Texas Non-ERCOT Load Serving Entity Fee

(1) The Texas Non-ERCOT Load Serving Entity (LSE) Fee is incurred by LSEs operating in areas where Customer Choice is in effect, for use of the statewide Customer registration system administered by ERCOT. This fee is based on the number of registered ESI IDs and billed to the LSE that serves the Customer at the ESI ID.

(2) The Texas Non-ERCOT LSE Fee is calculated daily, but billed to the non-ERCOT LSE as an aggregated total on a monthly basis.

$$\mathbf{NELF} = \mathbf{\Sigma(ESI_d * PED)}$$

The above variables are defined as follows:

Variable	Unit	Definition
NELF	$	***Non-ERCOT LSE Fee Charge*** - Non-ERCOT LSE Fee per month.
ESI_d	none	Number of ESI IDs per day
PED	$/ESIID	Per ESI ID fee

9.16.3 Application Fee

Each Entity that applies to become a registered Market Participant must pay any application fee under Section 16.

9.16.4 Private Wide Area Network Fees

A Market Participant connected to the Wide Area Network (WAN) shall pay a one-time installation fee and monthly maintenance fees related to access to the WAN as approved by the ERCOT Board. This fee is separate from the ERCOT System administration charge.

9.16.5 ERCOT Nodal Implementation Surcharge

ERCOT shall calculate the Nodal Implementation Surcharge (“NIS”) by multiplying total net metered generation by a nodal surcharge factor. The nodal surcharge factor will be a rate approved by the PUCT. The NIS will appear as a separate Market Service on the Settlement Statement. ERCOT shall charge the NIS on a daily basis to QSEs representing Generation

Resources, broken down by the appropriate quantity per Settlement Interval. QSE total net metered generation will be the total of the net metered generation aggregated to the QSE level. ERCOT will charge the NIS until it has recovered the full cost of implementing the nodal market redesign, at which time, ERCOT will cease collecting the NIS. The NIS is not a neutral fee, as it is the amount ERCOT collects to fund implementation of the nodal market redesign.

$$\mathbf{QNSAMT}_{q} = \mathbf{NODSF * (\sum_{p} \sum_{r} RTMG}_{q,\,p,\,r} + \sum_{p} \sum_{bltp} \mathbf{BLTR}_{q,\,p,\,bltp} + (\sum_{p} \mathbf{RTDCIMP}_{q,\,p} \mathbf{* ¼))}$$

The above variables are defined as follows:

Variable	Unit	Definition
QNSAMT $_{q}$	$	***Nodal Implementation Surcharge***—The nodal implementation surcharge for each QSE per 15-minute Settlement Interval.
RTMG $_{q, p, r}$	MWh	***Real-Time Metered Generation per QSE per Settlement Point per Resource***—The Real-Time energy produced by the Generation Resource r represented by QSE *q* at Resource Node *p*, for the 15-minute Settlement Interval.
BLTR $_{q, p, bltp}$	MWh	***Block Load Transfer Resource per QSE***—The energy delivered to an ERCOT Load through the BLT Point represented by the QSE, for the 15-minute Settlement Interval.
RTDCIMP $_{q, p}$	MW	***Real-Time DC Import per QSE***—The aggregated DC Tie schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie for the 15-minute Settlement Interval.
NODSF	$/MWh	***Nodal Surcharge Factor***—The nodal surcharge factor in dollars per MWh.
q	none	A QSE.
r	none	A Generation Resource.
bltp	none	A BLT Point.
p	none	A Settlement Point.

9.17 Transmission Billing Determinant Calculation

ERCOT shall provide Market Participants with the key parameters and formula components required by a TSP or DSP in determining the billing charges for the use of its Transmission Facilities or Distribution Facilities ("Transmission Billing Determinants"). ERCOT is not responsible for billing, collection, or disbursal of payments associated with transmission access service.

9.17.1 Billing Determinant Data Elements

(1) ERCOT shall calculate and provide to Market Participants on the MIS Secure Area the following data elements annually to be used by TSPs and DSPs as billing determinants for transmission access service. This data must be provided by December first of each year. This calculation must be made under the requirements of the PUCT. The data that is used to perform these calculations must come from the same systems used to calculate Settlement-billing determinants used by ERCOT.

(a) The 4-Coincident Peak (4-CP) for each DSP, as applicable;

(b) The ERCOT average 4-CP;

(c) The average 4-CP for each DSP, as applicable, coincident to the ERCOT average 4-CP;

(2) Average 4-CP is defined as “the average Settlement Interval coincidental MW peak occurring during the months of June, July, August, and September.”

(3) Settlement Interval MW coincidental peak is defined as “the highest monthly 15-minute MW peak for the entire ERCOT Transmission Grid as captured by the ERCOT Settlement system.”

9.17.2 Direct Current Tie Schedule Information

(1) By the seventh Business Day of each month, ERCOT shall provide the requesting TSP or DSP data pertaining to transactions over the DC Ties for the immediately preceding month. For each transaction, the following NERC tag data must be provided, at a minimum:

(a) NERC Tagging identifier (Tag Code);

(b) Date of transaction;

(c) Start and stop times;

(d) Megawatt-hours (MWh) actually transferred;

(e) Sending Generation Control Area (GCA);

(f) Receiving Load Control Area (LCA);

(g) Purchasing / Scheduling Entity (PSE);

(h) Entity scheduling the export of power over a DC Tie; and

(i) Status of Transaction (Implement, Withdrawn, Cancelled, Conditional, etc.).

(2) ERCOT shall maintain and provide the requesting TSP or DSP data pertaining to transactions over the DC Ties for the period from June 2001 to the present. For each transaction, the same data as specified in paragraph (1) above, must be provided.

9.18 Profile Development Cost Recovery Fee for Non-ERCOT Sponsored Load Profile Segment

(1) Paragraph (e)(3) of P.U.C. Subst. R. §25.131 (relating to Load Profiling and Load Research) requires that ERCOT establish and implement a process to collect a fee from any Retail Electric Provider (REP) who seeks to assign customers to a non-ERCOT sponsored profile segment. The process must include a method for other REPs who use the profile segment to compensate the original requestor of the new profile segment and for ERCOT to notify DSPs which REPs are authorized to use the new profile segment. This profile development cost recovery fee is overseen by ERCOT.

(2) Within 30 days after a profile segment receives final approval from ERCOT, the requestor shall submit to ERCOT documentation of the costs it incurred in developing the profile segment change request. All such documentation must be available for review by any Market Participant. Any costs submitted more than 30 days after approval of the profile segment will not be recoverable. Recoverable costs must be directly attributable to the creation of the profile segment change request, incurred no earlier than 24 months preceding the original submission date of the profile segment change request, and must be further limited to:

(a) Costs for Load research as paid to DSPs or ERCOT, documented by a copy of all DSP or ERCOT Invoices or other evidence of payment, including but not limited to:

(i) Buying and installing IDR meters;

(ii) Installing communication equipment such as phone lines or cell phones; and

(iii) Reading the meters and translating the data.

(b) Reasonable costs paid to third parties, including a copy of all third-party invoices or other documentary evidence of payment, including:

(i) Defining the request, such as identifying population, profile, data, etc.;

(ii) Preparing the request, such as collecting and analyzing data and presenting the case; and

(iii) Undertaking the review process such as meeting with ERCOT staff, Profiling Working Group (PWG), Retail Market Subcommittee (RMS), TAC, and the ERCOT Board.

(c) Requestor's reasonable internal documented costs itemizing all persons, hours, and other expenses associated with developing the request per paragraphs (1) and (2), above.

(3) Within 60 days after ERCOT approves a profile segment, ERCOT staff shall evaluate the costs submitted and shall disallow any costs not meeting these criteria. The remaining costs must comprise the total reimbursable cost. Within the same 60-day period, ERCOT shall post a report on the MIS Public Area summarizing the allowed expenses by paragraphs (1) and (2) above. If a Market Participant, including the requestor, disagrees with the ERCOT staff determination with respect to the total reimbursable cost, the Market Participant may submit a dispute as outlined in Section 20. No disputes may be submitted after 45 days from posting of the total reimbursable cost to the MIS Public Area.

(4) The fee is calculated as follows:

If a REP is the requestor, then: FEE = $C / n

If the requestor is not a REP, then:

FEE = $C / (n + 1)

The above variables are defined as follows:

Variable	**Definition**
N	The number of REPs subscribing to the profile segment
$C	The total reimbursable cost

(5) The fee must be paid by each successive subscribing REP to the requestor and any previous subscribing REPs per instructions and validation by ERCOT. As additional REPs subscribe to the profile segment, the fee is recalculated and reallocated equally among all subscribing REPs and the requestor, if the requestor is not a REP.

(6) Beginning four years after the date on which the profile segment becomes available for settlement, any REP may request assignment of ESI IDs to the profile segment without being assessed the profile development cost recovery fee.

ERCOT Nodal Protocols

Section 10: Metering

Updated: August 1, 2007

(Effective upon the [Nodal Protocol Transition Plan's]() Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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10 METERING

10.1 Overview

(1) This Section specifies the responsibilities and requirements for meter data, certification of Metering Facilities, meter standards, approved meter types and the process for auditing, testing, and maintenance of Metering Facilities to be used in the ERCOT Region. "Metering Facilities" means Revenue Quality Meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication Facilities and other related local equipment intended to supply ERCOT settlement quality data.

(2) Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) are the only Entities authorized to provide Settlement Meter data to ERCOT. ERCOT shall maintain a Meter Data Acquisition System (MDAS) to collect generation and consumption energy data for settlement purposes under these Protocols. The MDAS must receive Customer Load meter data from TSPs and DSPs and must collect data from all ERCOT-Polled Settlement (EPS) Meters.

(3) All Service Delivery Points (SDPs), excluding EPS, All-Inclusive Generation, or Non Opt-In Entity (NOIE) metering points, that meet the requirements of P.U.C.T. SUBST. R. 25.311 are eligible for competitive meter ownership pursuant to such PUCT Substantive Rule. All competitively owned meters shall meet all the applicable metering requirements of the ERCOT Protocols and Competitive Metering Guides.

10.2 Scope of Metering Responsibilities

10.2.1 QSE Real-Time Metering

The Qualified Scheduling Entity's (QSE's) responsibility for Real-Time metering requirements is contained in Section 6.5.5.2, Operational Data Requirements.

10.2.2 TSP and DSP Metered Entities

(1) Each TSP and DSP is responsible for supplying ERCOT with meter data associated with:

(a) All Loads using the ERCOT System;

(b) Any All-Inclusive Generation Resource that delivers less than 10 MW to the ERCOT System and that is connected directly to the distribution system; a DSP may make some or all such meters ERCOT-Polled Settlement (EPS) compliant and may request that ERCOT poll the meters. Notwithstanding the foregoing sentence, meter data is not required from:

(i) Generation owned by a NOIE and used for NOIE's self-use (not serving Customer Load); and

(ii) Renewable generation with a design capacity less than 50 kW interconnected to a DSP and not registered as a Generation Resource; and.

(c) NOIE points of delivery where metering points are radial Loads and are unidirectionally metered. A TSP or DSP has the option of making some or all such meters EPS compliant and to request that ERCOT poll the meters.

(2) Each TSP and DSP is responsible for the following:

(a) Compliance with the procedures and standards in this Section, the Settlement Metering Operating Guides (SMOG) and the Operating Guides;

(b) Installation, control, and maintenance of the Settlement Metering Facilities, as more fully described in this Section and SMOG, which includes meters, recorders, instrument transformers, wiring, and miscellaneous equipment required to measure electrical energy;

(c) Costs incurred in the installation and maintenance of these Metering Facilities and communications except for incremental costs incurred for functions not required for the settlement of the Load or All-Inclusive Resource. These incremental costs shall be borne by the Entities requesting the service pursuant to the TSP or DSP tariffs; and

(d) Installation, maintenance, data collection, and related communications, telemetry for the Metering Facilities, and related services necessary to meet the mandatory Interval Data Recorder (IDR) requirements detailed in this Section, Section 18, Load Profiling, and the SMOG.

10.2.3 ERCOT-Polled Settlement Meters

(1) ERCOT shall poll Metering Facilities that meet any one of the following criteria:

(a) Generation connected directly to the ERCOT Transmission Grid;

(b) Auxiliary meters used for generation netting by ERCOT;

(c) Generation delivering 10 MW or more to the ERCOT System;

(d) Generation participating in any Ancillary Service market;

(e) NOIE points connected bi-directionally to the ERCOT system; and

(f) Direct Current Ties.

(2) Additionally, ERCOT shall poll any All-Inclusive Generator or NOIE metering point at the request of such Entity, provided the Metering Facility meets all requirements and approvals associated with EPS metering requirements of this Section and the SMOG.

Load Resources of 10 MW or more on the ERCOT System, may, at their option have an EPS meter.

10.2.3.1 Entity EPS Responsibilities

The following defines the responsibilities of Entities regarding EPS metering:

(a) EPS Meters must be polled directly by ERCOT, which shall then convert the raw data to Settlement Quality Meter Data in accordance with this Section, Section 11, Data Acquisition and Aggregation, and the SMOG.

(b) A TSP or DSP shall have EPS Metering Facilities installed and maintained under the supervision of a TSP or DSP "EPS Meter Inspector," which is defined as an employee or agent of the TSP or DSP who has received EPS training from ERCOT, and is described further herein.

(c) Each TSP and DSP shall install, control, and maintain the meters, recorders, instrument transformers, wiring, communications, and other miscellaneous equipment required to measure electrical energy, as described in this Section and SMOG.

(d) Each TSP and DSP shall install and maintain a Back-up Meter(s)at each EPS Meter location for Resources, auxiliary netting, and bi-directional meter points. A "Back-up Meter" is defined as a redundant revenue quality EPS Meter connected at the same metering point as the primary EPS Meter and meeting the requirements defined in the SMOG.

(e) Costs incurred in the installation and maintenance of EPS metered Facilities and communications will be the responsibility of the TSP or DSP except for incremental costs incurred for functions not required for the energy settlement as required by these Protocols. These incremental costs shall be borne by the Entities requesting the service, as per the TSP's or DSP's tariffs.

(f) Specific operating practices for EPS Metering Facilities are included in the SMOG.

10.3 Meter Data Acquisition System (MDAS)

10.3.1 Purpose

The MDAS will be used:

(a) By ERCOT to obtain and receive Revenue Quality Meter data from the EPS Meters and Settlement Quality Meter Data from the TSP and DSP for settlement and billing purposes; and,

(b) To populate the ERCOT Data Archive used by Market Participants or their agents with authority to access Settlement Quality Meter Data held by ERCOT.

10.3.2 ERCOT-Polled Settlement Meters

(1) Each TSP and DSP shall, in accordance with these Protocols and the SMOG, provide ERCOT-approved metering communication equipment and connection to permit ERCOT access to the TSP's or DSP's EPS Meters.

(2) ERCOT shall retrieve meter data electronically and automatically by MDAS. ERCOT may also collect meter data on demand.

10.3.2.1 Generation Meter Splitting

(1) Each Generation Resource meter must be represented by only one QSE, except that a jointly owned Generation Resource unit or group of Generation Resources may split the net generation output into two or more virtual generating units for a Generation Entity. Each Generation Entity representing a virtual generating unit may have its energy and capacity scheduled through separate QSEs. For purposes of this paragraph, a jointly owned Generation Resource unit or group of Generation Resources shall also include the San Miguel and Gibbons Creek power projects, and intermittent Resources such as wind and solar generation.

(2) When the Generation Resource unit is registered with ERCOT, the Entities representing virtual generator units shall be required to submit a percentage allocation of the Resource to be used to determine the capacity available at each virtual generator unit.

(3) When the generator unit is registered with ERCOT, the owners of the unit shall submit all required ERCOT facility registration documentation and an ERCOT-approved splitting agreement executed by an authorized representative from each owning Entity. Such agreement shall contain a defined and fixed ownership percentage as among the owning Entities. ERCOT shall establish this generator as a "split," essentially establishing a virtual generator meter. Generation splitting based on a static ratio is not permitted. Generation splitting requires Real-Time splitting signals.

10.3.2.1.1 Generator Metering Real-Time Splitting Signal

(1) When the split-metered generating unit is registered at ERCOT, the Entities representing the virtual generator units shall select one master QSE to provide ERCOT with a Real-Time signal of the MW of generation per virtual generator unit. The signal must be sent from the master QSE's EMS system to ERCOT via the appropriate telemetry. The signal must be revised every scan cycle and must represent each virtual generator unit in positive MW. The signal must contain the Resource ID (RID) and the MW assigned to that RID.

(2) ERCOT shall integrate the signals and provide a MWh value for each 15-minute interval for each virtual generator unit. The settlement system must use the MWh per interval value to calculate the percentage breakdowns to be applied to the actual metered MWh values retrieved from the EPS metered Entity.

10.3.2.1.2 Allocating EPS Metered Data to Generator Virtual Meters

(1) ERCOT shall poll the EPS Metering Facilities related to the actual Generation Resource and store the meter data at 15-minute intervals. This metering data must be validated, edited, estimated, and compensated for losses, as necessary, and be netted as required. This resulting data must then have the virtual generator ratios applied to assign the generation to the QSE representing each owner of the virtual generators. The MWh quantities of the virtual generators must be used in all settlement calculations and reports.

(2) The following example illustrates the splitting of the generation data:

Splitting Example 1

Integrated values from ERCOT systems						**Actual Metered MWh**	**Data to be Used in Settlement**		
Interval Ending	**RID1 (MWh)**	**RID2 (MWh)**	**RID3 (MWh)**	**Total MWh**	**% Ratios Rid 1,2,3**		**Split MWh**	**Split MWh**	**Split MWh**
13:15	10	20	10	40	25, 50, 25	52	13	26	13

10.3.2.1.3 Processing for Missing Dynamic Splitting Signal

For any interval when ERCOT has not received a Real-Time signal for any one of the virtual generating units, ERCOT shall use the last valid percentage ratio for a completed interval.

Splitting Example 2

Integrated values from ERCOT systems						**Actual Metered MWh**	**Data to be Used in Settlement**		
Interval Ending	**RID1 (MWh)**	**RID2 (MWh)**	**RID3 (MWh)**	**Total MWh**	**% Ratios Rid 1,2,3**		**Split MWh**	**Split MWh**	**Split MWh**
13:15	10	20	10	40	25, 50, 25	52	13	26	13
13:30	NA	21	10	NA	Ratio Above	55	13.75	27.5	13.75
13:45	NA	22	10	NA	Ratio Above	48	12	24	12

10.3.2.1.4 Calculating the Virtual Generator Ratio

(1) For split-metered generating units, ERCOT shall provide for settlement the net MWh value for each 15-minute interval. This value is the MWh accumulated based on the MW value over each scan cycle. ERCOT shall use a standard "integration" mechanism to perform this function.

(2) For settlement, ERCOT shall use the integrated data to determine the allocation ratio as the integrated share of each signal divided by the integrated total of signals.

10.3.2.1.5 Generation Splitting Data Made Available to Market Participants

Market Participants shall have access to allocated generation output and ratio data only for virtual generators that they represent. ERCOT shall provide the allocation ratio for that RID. The master QSE for a split-metered generator unit shall have access to the allocation ratios and assigned generation output for units in which they act as the master QSE.

10.3.2.1.6 Allocating EPS Metered Data to Generator Owners When It Is Net Load

EPS Generation Resource sites that are netted by ERCOT may have multiple Competitive Retailers (CRs) associated with the Load. ERCOT shall poll the EPS metering facilities related to the actual Generation Resource facility and store the meter data at 15-minute intervals. ERCOT shall perform validation, editing, estimation, compensation for losses as necessary, and netting as required for EPS metering data. For intervals when data is net Load, the fixed ownership percentages stored in the asset database must be used to allocate the consumption to multiple Electric Service Identifier (ESI) IDs. The consumption quantities for the ESI IDs must be used in all energy settlement calculations and reports.

10.3.2.2 Loss Compensation of EPS Meter Data

(1) Where the EPS Meter is not located at the point of interconnection to the ERCOT Transmission Grid, actual metered consumption must be adjusted for line and transformation losses to the point of interconnection. The preferred method for loss compensation and correction is via internal meter programming.

(2) Recognizing the fact that some locations may not have the total functionality necessary to perform internal compensation, the Data Aggregation System (DAS) must have the functionality to perform approved loss compensation as necessary. ERCOT shall retain the discretion to allow or deny the continued use of this type of metering.

(3) No meter may be compensated internally for losses more than once. ERCOT may compensate multiple meters prior to netting to the point of interconnection. Pulse communications transfer of data between meters is not allowed.

10.3.2.3 Generation Netting for EPS Meters

(1) At Generation Resource Facilities, generation and associated Load must be metered at their points of interconnection to the ERCOT Transmission Grid. IDR meters must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the intervals where the Load exceeds the generation output, the net must be settled as Load and carry any applicable Load shared charges.

(2) For settlement purposes, generation netting is not allowed except under one of the following conditions:

(a) Single point of interconnection with delivered and received metering data channels;

(b) Multiple points of interconnection where the Loads and generator output are electrically connected to a common switchyard, as defined below. In addition, there must be sufficient generator capacity to serve all plant Loads for netting to occur;

(c) A Qualifying Facility (QF) with point(s) of interconnection where the QF is selling to the QF's thermal host(s) may net the Load meters of the thermal host with its generation meters when the Load and generation are electrically connected to a common switchyard. In instances in which Load is served by new on-site generation through a common switchyard, the TSP or DSP may install monitoring equipment necessary for measuring Load to determine stranded cost charges, if any are applicable, as determined under Public Utility Regulatory Act (PURA) and applicable PUCT rules. If the PUCT requires other Load served by onsite generators to pay the system benefit fund charges, then, in instances in which Load is served by generation through a common switchyard, the TSP or DSP may install metering equipment solely for purposes of the TSP's or DSP's calculation of system benefit fund charges, as provided by PURA, if any is applicable. For purposes of this Section, new on-site generation has the meaning as contained in Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.252 and § 39.262(k) (Vernon 1998 & Supp. 2005) (PURA); or

(d) For Generation Resources and/or Load with flow-through on a private, contiguous transmission system (not included in a TSP or DSP rate base) and in a configuration existing as of October 1, 2000, the meters at the interconnections with the ERCOT Transmission Grid may be netted for the purpose of determining Generation Resources or Load. For Settlement purposes, when the net is a Load, the metered interconnection points must be assigned to the same Load zone and UFE zone.

(e) ERCOT shall maintain descriptions of the metering facilities of all common switchyards that contain multiple points of interconnection of Loads (ESI IDs) and generation meters (EPS). The description is limited to identifying the Entities within a common switchyard and a simplified diagram showing the metering configuration of all Supervisory Control and Data Acquisition (SCADA) and settlement metering points.

(f) All Load(s) included in the netting arrangement for an EPS Metering Facility shall only be electrically connected to the ERCOT grid through the EPS metering point(s) for such Facility. Such Loads shall not be electrically connected to the ERCOT Grid through electrical connections that are not metered by the EPS metering point(s) for the Facility.

(3) For purposes of this Section, a common switchyard is defined as an electric substation facility where the point of interconnection for Load and Generation Resources are located at the same facility but where the interconnection points are physically not greater than 400 yards apart. The physical connections of the Load to its point of interconnection and the Generation Resource to its point of interconnection cannot be Facilities that have been placed in a TSP's or DSP's rate base.

10.3.2.4 Reporting of Net Generation Capacity

All Generation Resource facilities with associated Load shall report to ERCOT before February 1st of each year their projected Net Generation capacity available to the grid for use by others during the June to August time period for the current calendar year and five subsequent years in the same format as the generation capacity reports provided to the PUC.

10.3.3 TSP or DSP Metered Entities

10.3.3.1 Data Responsibilities

Each TSP and DSP shall be responsible for the following:

(a) Providing consumption data for each ESI ID and RID on a monthly basis according to the data timeliness and accuracy standards defined in this Section and in the SMOG;

(b) Providing start date, stop date, ESI ID or RID, and consumption data in kWh as well as an identifier for "estimated" reads as applicable;

(c) Submitting a single Demand value for each non-IDR ESI ID that has a demand register to ERCOT if, and only if, a Demand value is required for TSP or DSP tariffs or for CR Customer billing. If the CR and TSP or DSP do not require a Demand value, then the TSP or DSP shall not submit a Demand value to ERCOT even if the meter has a demand register;

(d) Validating, Editing, and Estimating (VEE) meter data according to the standards in this Section before submitting data to the settlement process;

(e) Calculating consumption for any unmetered services by ESI ID and submitting such data monthly to ERCOT, subject to ERCOT audit. These calculations must be made pursuant to TSP and DSP-approved tariffs; and,

(f) Metering all Loads, unless the Load meets the following criteria:

(i) Energy consumption by substation Facilities and equipment for the purpose of transporting electricity (e.g., substation transformers, fans, etc.).

(ii) Unmetered energy consumption represented by an ERCOT-approved Load Profile.

10.3.3.2 Retail Load Meter Splitting

Retail Service Delivery Points with Loads above 1 MW may split their actual meter data into a maximum of four consumption values with each value being assigned a unique ESI ID; provided, however, that if a Customer is using Provider of Last Resort (POLR) or the "Price-to-Beat" retail service, such Customer may not split its meter signal among multiple CRs through this Section.

10.3.3.2.1 Retail Customer Load Splitting Mechanism

Customer meter data may be split into separate ESI IDs by the installation of a programmable signal splitter that would take the master meter signal and split it into no more than four separate values that must at all times equal the total output of the master meter signal. Splitting of Customer meter data must meet the following requirements:

(a) The signal splitter may be programmed to split the Load in any way the Customer chooses, provided that such splitting results in positive Load;

(b) The Customer, or its CR(s), shall provide the signal splitter and shall be responsible for all costs of installing, maintaining, and operating the signal splitter, any associated equipment, and communications;

(c) The TSP or DSP shall be responsible for approving the specifications and installation of any signal splitting devices;

(d) Interval Data Recorders shall be required on the master Customer Load meter and each of the split channels for verification and settlement purposes;

(e) The TSP or DSP metering system recording such split signals (four ESI IDs) may be required to be redundant if so provided by TSP or DSP tariffs;

(f) The split signals must be recorded in Real-Time and cannot be altered or substituted later in time;

(g) One Entity shall be designated to pay the total TSP and/or DSP charges for the Customer; and,

(h) Switching of CRs for the individual split-metered Customers shall comply with the registration procedures in Section 19, Texas Standard Electronic Transaction (Texas SET).

10.3.3.2.2 TSP and DSP Responsibilities Associated with Retail Customer Load Splitting

(1) Each consumption value from a Customer Load split meter shall be assigned a separate ESI ID by the TSP or DSP. Each ESI ID may be assigned to a separate CR. The master meter may not be assigned an ESI ID.

(2) The TSP or DSP shall send interval data for each ESI ID for the ERCOT settlement system.

(3) The TSP or DSP shall be responsible for verifying that the sum of the split ESI ID IDR data equals the total IDR value from the master meter.

10.3.3.2.3 ERCOT Requirements for Retail Load Splitting

(1) ERCOT shall settle all ESI IDs in the same manner.

(2) ERCOT shall not receive or process the IDR data associated with the master meter.

10.3.3.3 Method for Interfacing with MDAS

(1) Settlement Meter data shall be submitted to ERCOT on a periodic cycle, but no later than monthly, using the Texas SET meter data exchange format. Each TSP or DSP shall ensure that consumption meter data submitted to ERCOT is in intervals of:

(a) 15-minutes for those ESI IDs and RIDs served by IDRs and,

(b) Monthly or on an ERCOT-approved meter reading cycle for non-IDR meters.

(2) The Settlement Quality Meter Data submitted by TSP or DSP must be in kWh and kVarh values (as applicable).

10.3.3.3.1 Past Due Data Submission

ERCOT shall provide a report to the appropriate TSP and DSP for any ESI ID or RID for which consumption data has not been received in the past 38 days. Upon receipt of the missing consumption data report, the TSP or DSP shall have two Business Days to submit the missing consumption data.

10.4 Certification of EPS Metering Facilities

Each TSP and DSP shall certify EPS Metering Facilities in a manner approved by ERCOT.

10.4.1 Overview

This Section describes the steps that a TSP or DSP shall use to certify each EPS Metering Facility and the steps ERCOT shall use to approve each EPS Metering Facility. This Section also describes the manner in which EPS Metering Facility approval requests must be made to ERCOT.

10.4.2 EPS Design Proposal Documentation Required from the TSP or DSP

Before installation of new EPS Meters, TSP or DSP shall provide ERCOT with an EPS Design Proposal of the Metering Facilities being considered for ERCOT approval as EPS Meter Facilities. An "EPS Design Proposal" is the documentation required on the form available on the MIS Public Area. Included one line drawings must be dated, detailed, bear the current drawing revision number, and show all devices which contribute to the burden in the metering circuits.. Other information may also be required by ERCOT for review regarding the meter and related installation and Facilities; such additional information shall be promptly provided to ERCOT by the TSP or DSP upon request of ERCOT.

10.4.2.1 Approval or Rejection of an EPS Design Proposal for EPS Metering Facilities

ERCOT may unconditionally approve, conditionally approve, or reject an EPS Design Proposal.

10.4.2.1.1 Unconditional Approval

If ERCOT unconditionally approves an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been approved. The TSP or DSP may then commence installation of the EPS Metering Facilities in accordance with the EPS Design Proposal.

10.4.2.1.2 Conditional Approval

(1) Notification of Conditional Approval:

If ERCOT conditionally approves an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been conditionally approved. It shall set forth in such Notice the conditions on which approval is granted and the time period in which each such condition must be satisfied by the TSP or DSP.

(2) Ability to Satisfy Conditions:

If the TSP or DSP disputes any condition imposed by ERCOT, the TSP or DSP must promptly notify ERCOT of its concerns and provide ERCOT with the reasons for its concerns. If the TSP or DSP provides ERCOT such Notice, ERCOT may amend or withdraw any of the conditions on which it granted its approval or ERCOT may require the TSP or DSP to satisfy other conditions. ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on accomplishing the installation.

(3) Notification of Satisfaction of Conditions:

The TSP or DSP shall promptly notify ERCOT when each condition in the approval has been satisfied and provide to ERCOT any information reasonably requested by ERCOT as evidence that such condition has been satisfied.

(4) Confirmation of Satisfaction of Conditions:

If ERCOT determines that a condition has been satisfied, then ERCOT shall provide the TSP or DSP written confirmation that the condition has been satisfied.

(5) Unsatisfied Conditions:

If ERCOT determines that a condition has not been satisfied, ERCOT shall notify the TSP or DSP that it does not consider the condition satisfied and shall set out in such Notice the reason(s) that it does not consider the condition satisfied. If, after using good faith efforts, ERCOT and the TSP or DSP are unable to agree on whether the condition is satisfied, either Entity may refer the dispute to the Alternative Dispute Resolution (ADR) Procedures as described in Section 20, Alternative Dispute Resolution Procedure.

10.4.2.1.3 Rejection

If ERCOT rejects an EPS Design Proposal, then ERCOT shall promptly notify the TSP or DSP that the EPS Design Proposal has been rejected and shall set forth the reasons for its rejection. The TSP or DSP shall submit to ERCOT a revised EPS Design Proposal after receiving such Notice. If ERCOT rejects for a second time an EPS Design Proposal submitted by a TSP or DSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on the requirements and disputed items. In the absence of agreement either Entity may refer the dispute to the ADR Procedures as described in Section 20, Alternative Dispute Resolution Procedures.

10.4.3 Site Certification Documentation Required from the TSP or DSP EPS Meter Inspector

(1) A TSP or DSP EPS Meter Inspector shall complete an ERCOT site certification form for each set of EPS Metering Facilities that it inspects. The site certification form is the official form used to document whether EPS Metering Facilities meet ERCOT criteria.

(2) The TSP or DSP EPS Meter Inspector shall promptly notify ERCOT and document any discrepancy between ERCOT approved EPS Design Proposal on file and the actual Metering Facilities inspected by the TSP or DSP EPS Meter Inspector.

(3) The TSP or DSP shall provide the documents as outlined in SMOG for each set of EPS Metering Facilities being considered for ERCOT approval.

10.4.3.1 Review by ERCOT

(1) ERCOT shall review the ERCOT site certification documentation prepared by the TSP or DSP EPS Meter Inspector within 45 days of receipt. If ERCOT finds that this data is incomplete or demonstrates that the EPS Metering Facilities fail to meet the standards contained within this Section or the SMOG, ERCOT shall promptly provide written or electronic notice of the deficiencies to the TSP or DSP.

(2) ERCOT shall notify the TSP or DSP of the approval of the Metering Facility. ERCOT shall return the original schematic drawings, and the original ERCOT site certification form stamped by ERCOT as approved. ERCOT shall retain a copy of these documents.

10.4.3.2 Provisional Approval

If ERCOT finds that the documentation: provided by the TSP or DSP is incomplete or demonstrates that the EPS Metering Facility fails to meet the standards contained within this Section and SMOG; then ERCOT may, elect to issue a provisional approval for the Metering Facility. The terms and conditions on which such provisional approval is issued shall be at ERCOT’s discretion and shall be defined for the TSP or DSP. ERCOT shall not issue an approval until such time as all of the conditions of the provisional approval have been fulfilled to the satisfaction of ERCOT. ERCOT shall post any provisional approvals on the MIS Public Area on a quarterly basis.

10.4.3.3 Obligation to Maintain Approval

Once an EPS Metering Facility has been installed, it is the responsibility of the TSP or DSP to ensure that the EPS Metering Facility complies with the approval criteria referred to in this Section and the SMOG.

10.4.3.4 Revocation of Approval

(1) ERCOT may revoke in full or in part any approval of Metering Facilities, including a provisional approval if:

(a) ERCOT or a TSP or DSP EPS Meter Inspector demonstrates that all or part of the EPS Metering Facilities covered by that approval no longer meet the approval criteria for EPS Metering Facilities contained in this Section and the SMOG; and

(b) ERCOT has given written Notice to the TSP or DSP stating that the identified EPS Metering Facilities do not meet the approval criteria and the reasons and that the TSP or DSP fails to correct the deficiency and satisfy ERCOT, within 30 days, that the EPS Metering Facilities meet the approval criteria.

(2) If ERCOT revokes in full or part an approval of EPS Metering Facilities, the TSP or DSP may seek re-approval of the EPS Metering Facilities by requesting approval in accordance with this Section.

10.4.3.5 Changes to Approved EPS Metering Facilities

Each TSP and DSP shall notify ERCOT of any planned modifications or changes to be made to any EPS Metering Facilities that would affect the EPS Metering Facility's approval, not less than ten Business Days prior to the intended implementation of the change. Before the intended date of the change, ERCOT may request additional information from the TSP or DSP to demonstrate that the EPS Metering Facilities will still meet the applicable approval standards; the TSP or DSP shall promptly comply with such request for information. ERCOT may at its discretion audit Metering Facilities to determine compliance. The TSP or DSP shall provide ERCOT with meter specific program details, as downloaded from the meter, when the EPS Meter is programmed.

10.4.3.6 Confirmation of Certification

On the written request of ERCOT, the TSP or DSP shall provide ERCOT written or electronic confirmation that the Metering Facilities of each metered Entity that the TSP or DSP represents have been certified in accordance with this Section and the SMOG within five Business Days of receiving such a request from ERCOT.

10.5 TSP and DSP EPS Meter Inspectors

10.5.1 List of TSP and DSP EPS Meter Inspectors

ERCOT shall maintain a list of TSP and DSP EPS Meter Inspectors, and details related to ERCOT training to become a TSP or DSP EPS Meter Inspector.

10.5.2 EPS Meter Inspector Approval Process

10.5.2.1 TSP and DSP Responsibilities

(1) Each TSP and DSP shall ensure that personnel performing EPS Meter Facility certification duties are approved EPS Meter Inspectors and comply with this Section and the SMOG. A TSP or DSP EPS Meter Inspector is required to complete an ERCOT EPS Meter Inspector training session.

(2) The TSP and DSP shall submit to ERCOT the following information for individuals performing EPS Metering Facility certification.

(a) Name of individual;

(b) Time period the individual has been testing Generation Resource or transmission interconnect metering points;

(c) TSP or DSP statement indicating that the individual has the technical expertise to perform EPS Metering Facility certification; and,

(d) Additional documentation as required by ERCOT.

10.5.2.2 ERCOT Responsibilities

(1) ERCOT shall hold EPS Meter Inspector training sessions on a regularly scheduled basis. Sessions must include information on the following:

(a) Market responsibilities of EPS Meter Inspectors;

(b) Documentation requirements for the site certification;

(c) Overview of EPS Metering Facilities related topics and documents;

(d) Protocols requirements;

(e) SMOG requirements; and,

(f) Technical requirements.

(2) ERCOT shall issue a certificate of attendance to individuals upon completion of the EPS Meter Inspector training sessions.

(3) ERCOT shall have the authority to revoke an individual's involvement with EPS Metering Facility certification.

10.6 Auditing and Testing of Metering Facilities

10.6.1 EPS Meter Entities

10.6.1.1 ERCOT Requirement for Audits and Tests

ERCOT shall have the right to audit any EPS Metering Facility that it considers necessary or to request and witness a test carried out by a TSP or DSP EPS Meter Inspector.

10.6.1.2 TSP and DSP Testing Requirements for EPS Metering Facilities

(1) At a minimum, the TSP and DSP EPS Meter Inspector shall conduct testing of EPS Meters on an annual basis, within the same month of each year as the previous year's test.

Metering Facilities used in the ERCOT system for settlement must be tested pursuant to the TSP or DSP tariffs, the SMOG and these Protocols.

(2) Instrument transformers used in settlement metering circuits must be tested using the following guidelines:

(a) Magnetic Instrument Transformers do not require periodic testing as they have shown themselves to be stable per ANSI C12.1.;

(b) Coupling Capacitor Voltage Transformers (CCVTs) shall, at a minimum, be tested for accuracy on a five year cycle, by the end of the fifth year after the previous test; and,

(c) Fiber-optic Current Transformers (CTs) shall, at a minimum, be ratio tested on a five year cycle, by the end of the fifth year after the previous test. .

(3) ERCOT may determine that periodic testing of CCVTs and fiber-optic CTs is not required once these devices have been proven to be stable. If the devices have shown themselves to be unstable, ERCOT may discontinue the use of these devices for settlement purposes.

10.6.1.3 Failure to Comply

If an EPS Metering Facility fails to comply with ERCOT's audit or test procedures, ERCOT shall issue a warning to the TSP or DSP responsible for such Metering Facilities. If the TSP or DSP fails to comply with ERCOT's recommendations in a reasonable time, as determined by ERCOT, ERCOT shall notify the PUCT or the appropriate Governmental Authority.

10.6.1.4 Requests by Market Participants

Market Participants shall follow appropriate Governmental Authority rules for requesting the testing of Metering Facilities.

10.6.2 TSP and DSP Metered Entities

10.6.2.1 Requirement for Audit and Testing

(a) Audit and Testing by a TSP or DSP

Each TSP or DSP shall conduct (or engage a qualified Entity to conduct) audits and tests of the Metering Facilities of the TSP or DSP Metered Entities that it represents to ensure compliance with all applicable requirements of any relevant Governmental Authority. Each TSP and DSP shall undertake any other actions that are reasonably necessary to ensure the accuracy and integrity of the meter data.

(b) Audit and Testing Requests by an affected Market Participant

Subject to any applicable Governmental Authority requirements, an affected Market Participant shall have the right to witness an audit or test carried out by the TSP or DSP or its authorized representative.

10.6.2.2 TSP and DSP Requirement to Certify per Governmental Authorities

If a Governmental Authority has authority to certify meter installations, then the TSP or DSP shall comply with such regulations.

10.7 ERCOT Request for Installation of EPS Metering Facilities

10.7.1 Additional EPS Metering Installations

(1) If ERCOT determines that there is a potential need to install additional EPS Metering Facilities on the ERCOT System, ERCOT shall notify the relevant TSP or DSP in writing or electronically. ERCOT's Notice must include the following information:

(a) The location of the meter point at which the additional EPS Metering Facilities are required;

(b) The projected installation date by which the relevant EPS Metering Facilities should be installed;

(c) The reason for the need to install the additional EPS Metering Facilities; and

(d) Any other information that ERCOT considers relevant.

(2) A TSP or DSP that is notified by ERCOT of the potential need to install additional EPS Metering Facilities must:

(a) Give ERCOT written confirmation of receipt of Notice within three Business Days of receiving such Notice;

(b) Submit an EPS Design Proposal to ERCOT within 45 Business Days of receiving such Notice.

(3) The TSP or DSP may request a waiver to install additional Metering Facilities.

10.7.2 Approval or Rejection of Waiver Request for Installation of EPS Metering Facilities

ERCOT may approve, or reject a waiver request at ERCOT's sole discretion.

10.7.2.1 Approval

If ERCOT approves a waiver request, then ERCOT shall promptly notify the TSP or DSP.

10.7.2.2 Rejection

If ERCOT rejects a waiver request, then ERCOT shall promptly notify the TSP or DSP and shall set forth the reasons for its rejection. The TSP or DSP may submit to ERCOT a revised waiver request within 14 Business Days of receiving such Notice. If ERCOT rejects for a second time a waiver request submitted by a TSP or DSP with respect to the same or similar Notice issued by ERCOT as described above, then ERCOT and the TSP or DSP shall use good faith efforts to reach agreement on the requirements and disputed items. In the absence of agreement either Entity may refer the dispute to the ADR Procedures as described in Section 20, Alternative Dispute Resolution Procedures.

10.8 Maintenance of Metering Facilities

10.8.1 EPS Meters

10.8.1.1 Duty to Maintain EPS Metering Facilities

Each TSP and DSP shall maintain its EPS Metering Facilities to meet the standards prescribed by this Section and the SMOG. If the EPS Metering Facilities of a TSP or DSP require maintenance to ensure that they operate in accordance with the requirements of this Section, SMOG, or any Governmental Authority, then the TSP or DSP shall notify ERCOT of the need for such maintenance. The TSP or DSP shall also inform ERCOT five Business Days in advance of the time period during which such maintenance is expected to occur. During that period, the TSP or DSP, or its authorized representative, after notifying ERCOT, shall be entitled to access sealed EPS Metering Facilities to which access is required in order to undertake the required maintenance.

10.8.1.2 EPS Metering Facilities Repairs

If an EPS Metering Facility requires repairs to ensure that it operates in accordance with the requirements of this Section, then the TSP or DSP shall immediately notify ERCOT of the need for repairing such Metering Facility. If, however, operating conditions are such that it is not possible for the TDSP to notify ERCOT of the need for repairs, then the TDSP may make the necessary repairs and then notify ERCOT of the repairs prior to the end of the next Business Day.

(a) Where no Back-up Meter exists or Back-up Meter data is unavailable, the TSP or DSP shall ensure that the metering point is repaired and operational within 12 hours of problem detection;

(b) Where a functional and operational Back-up Meter exists, the TSP or DSP shall ensure that the metering point is repaired and operational within five Business Days of problem detection.

10.8.2 TSP or DSP Metered Entities

Each TSP and DSP shall maintain its Metering Facilities in accordance with the requirements of the relevant Governmental Authorities and according to this Section.

10.9 Standards for Metering Facilities

For settlement purposes, IDR meters are required on any of the following locations/sites:

(a) All-Inclusive Generation Resources (with the exception of those excluded in this Section);

(b) Resources bidding into the Ancillary Services Market;

(c) NOIE metering points used to determine NOIE total Load;

(d) Service Delivery Points connected to the transmission system (>60KV); and,

(e) Locations meeting IDR Requirements defined in Section 18, Load Profiling.

10.9.1 ERCOT-Polled Settlement Meters

(1) The TSP or DSP for EPS meters shall ensure that the EPS Metering Facilities comply with this Section and the SMOG.

(2) IDR meters used for settlement of EPS Metering Facilities shall:

(a) Capture energy consumption and/or production in increments consistent with ERCOT defined Settlement Interval;

(b) Be able to capture energy in increments of five minutes (excluding memory allocation) for new and replacement IDR meters used for settlement;

(c) Provide interval data for daily polling on a schedule that supports ERCOT's requirements (typically a daily cycle);

(d) Be capable of having data retrieved via telemetry by MDAS;

(e) Have battery or other energy-storage back-up to maintain time during power outages;

(f) Have remote time synchronization capability compatible with the MDAS;

(g) Maintain meter clocks on a time reference standard that enables ERCOT MDAS to maintain the IDR data on the Central Prevailing Time. The meter clock shall be synchronized to within +/- one percent (1%) of the Settlement Interval when compared with the National Institute of Standards and Technology (NIST) Atomic Clock. ERCOT shall perform the time synchronization for meters at the time of the interrogation if the meter is outside tolerance; and,

(h) Divide each hour into Settlement Intervals ending as follows:

XX:15:00
XX:30:00
XX:45:00
XX:00:00

10.9.2 TSP or DSP Metered Entities

IDR meters used for settlement of TSP or DSP Metered Entities shall:

(a) Capture energy consumption in increments consistent with, or in fractions of, ERCOT-defined settlement time interval;

(b) Provide interval data on a schedule that supports the requirements of final settlement;

(c) Have battery or other energy-storage back-up to maintain time during power outages;

(d) Have time synchronization capability;

(e) Maintain meter clocks on a time reference that enables the TSP or DSP to submit data on the Central Prevailing Time. The meter clock shall be synchronized to within at least +/- 5% of the Settlement Interval when compared to the National Institute of Standards and Technology (NIST) Atomic Clock;

(f) Have data aggregated to the appropriate Settlement Interval time block by the TSP or DSP prior to the data being sent to ERCOT if recorded at increments less than the ERCOT defined settlement interval;

(g) Be able to capture energy in increments of five minutes (excluding memory allocation) for new and replacement IDR meters used for settlement;

(h) Divide each hour into Settlement Intervals ending as follows:

XX:15:00
XX:30:00
XX:45:00
XX:00:00

(i) IDR data submitted to ERCOT for Operating Days January 1, 2003, or later must contain only whole days with start times beginning at 0000 and stop times ending at 2359.

10.9.3 Failure to Comply with Standards

If the TSP or DSP fails to comply with the standards for EPS Metering Facilities referred to in this Section and the SMOG, then ERCOT shall notify the PUCT or the appropriate Governmental Authority.

10.10 Security of Meter Data

10.10.1 EPS Meters

(1) A TSP or DSP is responsible for data security of the EPS Metering Facilities on their system. This responsibility extends to third-party contracts and access to EPS Metering Facilities.

(2) A TSP, DSP or any Entity authorized to poll EPS Meters may not issue any EPS Meter programming passwords to any Market Participant.

10.10.1.1 TSP and DSP Data Security Responsibilities

Each TSP and DSP shall:

(a) Maintain and modify the passwords for programming and read access to EPS Meters;

(b) Provide the appropriate password access to ERCOT, which will allow ERCOT to synchronize the meter clock;

(c) Establish any other security requirements for accessing the EPS Meters so as to ensure the security of those meters and their meter data;

(d) Coordinate any EPS Meter programming parameter changes with ERCOT according to this Section, including informing the Load or Resource Entity of any changes to the meter;

(e) Upon request of the Resource Entity that represents an EPS metered facility, provide the EPS meter “read only” password to such Resource Entity for such facility and other EPS metered facility required to calculate their QSE Load, to the extent that such provision does not violate the Customer service and protection provisions of the PUCT Substantive Rules; and

(f) Modify the “read only” password for EPS meters when a Resource Entity that represents a facility requests a change due to data security reasons, provided that such modification does not violate the Customer service and protection provisions of the PUCT Substantive Rules.

10.10.1.2 ERCOT Data Security Responsibilities

ERCOT may request that TSP or DSP alter the password and other requirements for accessing EPS Meters, as it deems necessary.

10.10.1.3 Resource Entity Data Security Responsibilities

A Resource Entity must request that the TSP or DSP modify the EPS Meter "read only" password for a facility when the Resource Entity relationships that affect EPS Meter data security change. Such request must include the reason for the request.

10.10.1.4 Third Party Access Withdrawn

If, in the reasonable opinion of ERCOT, access granted to a third party interferes with or impedes ERCOT's ability to poll any EPS Meter, ERCOT may require immediate withdrawal of any access granted to such third party. Separate access through additional communications ports may be allowed so long as it does not interfere with ERCOT's ability to communicate with the meter.

10.10.1.5 Meter Site Security

(1) EPS Metering Facilities and secondary devices that could have any impact on the performance of the EPS Metering Facilities must be sealed to the extent practicable.

(2) ERCOT shall provide each TSP and DSP with uniquely numbered seals to be used by the TSP or DSP EPS Meter Inspector to seal EPS Meters and EPS Meter test switches. Procedures for seal use shall be in accordance with this Section and the SMOG.

10.10.2 TSP or DSP Metered Entities

Security for TSP and DSP polled meters and meter data shall be the responsibility of the TSP or DSP. Each TSP and DSP shall maintain polled meters in accordance with applicable Governmental Authority rules and regulations. The TSP and DSP shall ensure that only Customer-approved Market Participants have access to the Customer meter.

10.11 Validating, Editing, and Estimating of Meter Data

10.11.1 EPS Meters

The raw meter data that ERCOT retrieves from EPS Meters must be processed by MDAS using the Validating, Editing, and Estimating (VEE) procedures published in Section 11, Data Acquisition and Aggregation, and the SMOG in order to produce Settlement Quality Meter Data. During periods for which no primary EPS Meter data is available, ERCOT shall use the backup meter data or substitute estimated usage data for that metered Entity using estimation procedures referred to in these Protocols and the SMOG. This data shall be used by ERCOT in its settlement and billing process.

10.11.2 Obligation to Assist

At the request of ERCOT, a TSP, DSP and Market Participant shall promptly assist ERCOT in correcting or replacing defective data from EPS Meters and in detecting and correcting underlying causes for such defects. Such assistance shall be rendered in a timely manner so that the settlement process is not delayed.

10.11.3 TSP or DSP Settlement Meters

(1) The TSP and DSP shall provide ERCOT with Settlement Quality Meter Data for the TSP or DSP Settlement Meters on its system and shall ensure that at a minimum the VEE requirements as specified in the Uniform Business Practices (UBP) standard for Validating, Editing, and Estimating have been properly performed on such data. ERCOT shall not perform any VEE on the Settlement Quality Meter Data it receives from TSP or DSP.

(2) The following UBP manual validation processes are exempt for Interval Data:

(a) Spike Check; and

(b) Reactive channel check for kWh data

10.12 Communications

10.12.1 ERCOT Acquisition of Meter Data

ERCOT shall acquire meter data via the following communication links:

(a) ERCOT private communication network established by ERCOT for ERCOT Real-Time metered Entities; and

(b) Standard voice telephone circuit or other ERCOT-approved communication technology provided by the TSP or DSP for EPS Meters.

10.12.2 TSP or DSP Meter Data Submittal to ERCOT

TSP and DSPs shall submit meter consumption data to ERCOT through a standard data interface into the MDAS. In order to submit meter consumption data, a TSP or DSP shall use an automated system with an ERCOT-approved and tested interface to MDAS.

10.12.3 ERCOT Distribution of Settlement Meter Data

ERCOT shall distribute Settlement Quality Meter Data to Market Participants:

(a) Whenever a TSP or DSP submits meter consumption data to ERCOT, information pertaining to specific Market Participants shall be removed and automatically forwarded on to that specific Market Participant (i.e., a CR will automatically receive the meter consumption data and other information for the ESI IDs that the CR represented during the meter data timeframe.); and

(b) On Request – An Market Participant may submit an electronic request via the MIS Certified Area for specific meter consumption data. ERCOT will receive and validate the request and, if appropriate, automatically forward the appropriate information to the Market Participant.

10.13 Meter Identification

The device id used to identify an EPS Meter shall be unique for such meters on the ERCOT System. ERCOT shall maintain a master list of device ids and shall notify each TSP and DSP if the device id selected has been used elsewhere in MDAS.

10.14 Exemptions from Compliance to Metering Protocols

10.14.1 Authority to Grant Exemptions

ERCOT may grant on a case by case basis, exemptions from compliance on a temporary basis until new arrangements can be completed in accordance with the guidelines as listed below. Any permanent exemption to this Section requires approval by the Technical Advisory Committee (TAC) and the ERCOT Board. Any permanent exemption shall be subject to periodic review and revocation by the ERCOT Board.

10.14.2 Guidelines for Granting Temporary Exemptions

ERCOT shall use the following process when considering applications for temporary exemptions from compliance with this Section and the SMOG.

(a) Publication of Guidelines: ERCOT shall post on the MIS Public Area the general guidelines that it will use when considering applications for exemptions within five Business Days of a change of guidelines, so as to achieve consistency in its reasoning and decision-making and to give prospective applicants an indication of whether an application for exemption may be considered favorably.

(b) Publication of Decision: ERCOT shall post on the MIS Public Area the application for exemption and whether the application was approved or rejected by ERCOT and the reasons for rejecting the application, if applicable, on a quarterly basis.

10.14.3 Procedure for Applying for Exemptions

(1) All applications to ERCOT for exemptions from compliance with the requirements of this Section must be submitted in writing. ERCOT shall confirm receipt of an application within three Business Days of receipt. For temporary exemptions, ERCOT shall decide whether to grant or reject the exemption within 45 Business Days of receipt. For permanent exemptions, ERCOT shall forward the application to TAC for review at the next scheduled meeting for which appropriate Notice can be made. At any time during the application process, ERCOT may require the applicant to provide additional information in support of its application.

(2) The applicant shall provide such additional information to ERCOT within five Business Days of receiving the request or within such other period as ERCOT may specify. If ERCOT requests additional information more than 40 Business Days after the date on which it received the application, ERCOT shall have an additional seven Business Days after receiving that additional information in which to consider the application. If the applicant does not provide the additional information requested, then ERCOT shall reject the application, in which case it will notify the applicant that its application has been rejected for failure to provide the additional information.

10.14.3.1 Information to be Included in the Application

The application for exemption to ERCOT shall include:

(a) A detailed description of the exemption sought. including specific reference to the relevant Section(s) of these Protocols or the SMOG authorizing ERCOT to grant the exemption, and the Metering Facilities to which the exemption will apply;

(b) A detailed statement of the reason for seeking the exemption, including any supporting documentation;

(c) Details of the Entity(s) to which the exemption will apply;

(d) Details of the location to which the exemption will apply;

(e) Details of the period of time for which the exemption will apply, including the proposed start and finish dates of that period; and,

(f) Any other information requested by ERCOT.

ERCOT Nodal Protocols

Section 12: Market Information System

Updated: September 23, 2005

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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12 MARKET INFORMATION SYSTEM

12.1 Overview

(1) ERCOT shall create and maintain an electronic Market Information System ("ERCOT Market Information System" or "MIS"). Part of the MIS contains information available to the public in the MIS Public Area; part of the MIS contains information available only to applicable Entities in the MIS Secure Area; and part of the MIS contains information available only to an individual Market Participant in the MIS Certified Area. The MIS Secure Area provides restricted access to critical energy infrastructure information.

(2) ERCOT shall also create and maintain an Internet website with public and restricted areas.

12.2 ERCOT Responsibilities

(1) ERCOT shall post information to the MIS as directed throughout these Protocols. With the exception of information requested by a Market Participant in accordance with (3) below, ERCOT may not use the MIS to post information beyond that specifically required in these Protocols.

(2) ERCOT may use its Internet web site to communicate information that is not posted to the MIS.

(3) To the extent a request is reasonable, in ERCOT's sole discretion, ERCOT shall post to the MIS Certified Area information that is requested by a Market Participant but not required to be posted by these Protocols.

(4) ERCOT shall create and maintain a list of all of the posting requirements contained in these Protocols. This list, and changes thereto, shall be posted to the MIS Public Area.

(5) ERCOT shall post the list of Other Binding Documents to the MIS Public Area.

12.3 MIS Administrative and Design Requirements

The MIS must comply with the administrative and design requirements specified as follows:

(a) ERCOT shall ensure that all Market Participants have access to the ERCOT MIS on a nondiscriminatory basis.

(b) The MIS must, at a minimum, provide all information required under any regulations of the Public Utility Commission of Texas (PUCT) or other Governmental Authorities.

(c) The MIS must include any available information that may be used by a Qualified Scheduling Entity (QSE) to estimate or verify bills for all ERCOT-provided settlements.

(d) At the request of an Eligible Transmission Service Customer, ERCOT shall provide the methodology and data to independently reproduce information contained in the MIS related to the operation of the ERCOT market.

(e) The MIS must include security measures to protect the confidentiality of Protected Information as required by these Protocols.

(f) The MIS must comply with industry standards for commercial websites, including query and search functionality.

(g) The MIS must provide easy navigation based on the posting list described in Section 12.2(4) above for document retrieval. This navigability must include hyperlinks between listings and the MIS posted information.

(h) The MIS must provide easy navigation to the Other Binding Documents described in Section 12.2(5) above. This navigability must include hyperlinks between listings and the documents.

12.4 ERCOT Internet Website

ERCOT shall create and maintain an Internet website consistent with industry standards for commercial websites, including query and search functionality. The MIS or a link to the MIS must be available from that Internet website. ERCOT may use its Internet web site to communicate information that is not posted to the MIS.

ERCOT Nodal Protocols

Section 13: Transmission and Distribution Losses

Updated: August 1, 2007

(Effective upon the [Nodal Protocol Transition Plan's]() Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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13 TRANSMISSION AND DISTRIBUTION LOSSES

13.1 Overview

This section sets forth the method for calculating Transmission and Distribution Losses (T&D Losses) and responsibilities of ERCOT, Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) with respect to T&D Losses.

13.1.1 Responsibility for Transmission and Distribution Losses

(1) T&D Losses are the responsibility of the QSE representing the Competitive Retailer's Load. The QSE will schedule the necessary amount of energy to cover the Competitive Retailer's Load plus the applicable T&D Losses. ERCOT shall allocate T&D Losses to Load at the appropriate aggregate level as part of the data aggregation process to calculate the Load obligation of QSEs for settlement purposes.

(2) ERCOT shall forecast Transmission Loss Factors (TLFs) and post them to the MIS Public Area by 0600 of the Day Ahead period. ERCOT shall forecast the ERCOT-wide TLFs as a percentage of Load for each Settlement Interval of the Operating Day. By the close of business on the day following the Operating Day, ERCOT shall also calculate TLFs for each Settlement Interval using the actual system Load for that Settlement Interval and shall post the resulting deemed actual TLFs to the settlement system and the MIS Public Area.

(3) ERCOT shall forecast Settlement Interval Distribution Loss Factors (DLFs) and post them to the MIS Public Area by 0600 of the Day Ahead period. ERCOT shall forecast the Settlement Interval DLFs as a percentage of Load for each Settlement Interval of the Operating Day. On the day following the Operating Day, ERCOT shall also calculate Settlement Interval DLFs using actual system Load for that Settlement Interval and post the resulting deemed actual Settlement Interval DLFs to the settlement system and the MIS Public Area.

(4) Distribution loss coefficients, and the calculation methodology from which they are derived, will be subject to audit by ERCOT for accurate and consistent application. Non-Opt-in Entities (NOIE) with Interval Data Recorders at the settlement point of delivery are not required to provide Distribution loss coefficients and calculation methodology.

(5) In the special case where there are distribution facilities upstream from a wholesale NOIE settlement IDR, that NOIE settlement IDR will be compensated for line and transformer losses between the IDR and the ERCOT Transmission Grid to account for the Distribution Losses. The NOIE will be then treated as a transmission level NOIE. Calculations are subject to review by ERCOT. Since loss compensation is included in the wholesale settlement IDR, the TSP and/or DSP providing upstream wheeling facilities may need to offer wholesale wheeling tariffs excluding the losses that have already been compensated for.

13.1.2 Calculation of Losses for Settlement

ERCOT shall use the deemed actual Settlement Interval DLFs applicable to each ESI ID and the deemed actual Settlement Interval TLFs when adjusting aggregated Load for losses to determine the QSE total Load obligations.

13.2 Transmission Losses

13.2.1 Forecasted Transmission Loss Factors

(1) The forecasted TLF for each interval in the Operating Day shall be a linear interpolation or extrapolation using the on-peak and the off-peak TLFs and the corresponding forecast of ERCOT System Load during the same interval to calculate the loss factors.

(2) At 0600 of the Day Ahead period, ERCOT shall forecast a TLF for each Settlement Interval of the Operating Day and post on the MIS Public Area the forecasted TLFs which correspond to the Operating Day forecast. The source of the on-peak and off-peak losses are the ERCOT load flow base cases for the applicable month.

13.2.2 Deemed Actual Transmission Loss Factors

(1) ERCOT shall determine the deemed actual TLF for each interval in the Operating Day, by use of a linear interpolation or extrapolation using the on-peak and the off-peak TLFs corresponding to the actual ERCOT System Load during the interval.

(2) The day after the Operating Day, ERCOT shall calculate deemed actual TLFs for each Settlement Interval of the Operating Day and publish the TLFs to be used in settlement calculations.

(3) ERCOT shall use the TLFs corresponding to the on-peak and off-peak base case ERCOT System Loads during the applicable months as the basis for the ERCOT-wide deemed actual TLFs. ERCOT will post TLFs to the MIS Public Area by 0600 two days after the Operating Day.

13.2.3 Transmission Loss Factor Calculations

The following formulas shall be used to translate the monthly on-peak and off-peak TLFs into Settlement Interval TLFs.

$$\text{TLF}_i = (\text{MSC} * \text{SIEL}_i) + \text{MIC}$$

Variable	**Unit**	**Description**
i	none	Interval
TLF_i	none	Transmission Loss factor for a settlement interval
SIEL_i	MWh	Settlement Interval ERCOT System Load (forecasted or actual)
MSC	none	Monthly Slope Coefficient
MIC	none	Monthly Intercept Coefficient

And

MSC = (MONLF – MOFFLF)/(MONL-MOFFL)

MIC = [(MOFFLF*MONL)-(MONLF*MOFFL)]/(MONL-MOFFL)

Variable	Unit	Description
MONLF	none	Monthly on-peak percent loss factor
MOFFLF	none	Monthly off-peak percent loss factor
MONL	none	Monthly on-peak Load value
MOFFL	none	Monthly off-peak Load value

13.2.4 Monthly Transmission Loss Factor Calculation

(1) Monthly on-peak and off-peak TLFs are derived from the monthly updated ERCOT on-peak and off-peak load flow base cases analysis by ERCOT. Base cases reflect the most current data on the transmission system and Generation Resource dispatch. The ERCOT Transmission Grid topology and related Generation Resource dispatch in the base cases are the critical factors in calculating losses.

(2) ERCOT shall calculate monthly TLFs by dividing ERCOT monthly case transmission losses (60 kV system and higher) by the ERCOT monthly base Load adjusted (reduced) for self serve Load modeled in the case. The resulting loss factors are expressed as a percentage of Load.

(3) ERCOT shall post to the MIS Public Area monthly TLFs 30 days prior to the start of the month. The posting will include monthly on-peak and off-peak cases for 18 months in the future.

13.2.5 Loss Monitoring

ERCOT shall monitor Transmission Losses annually and will investigate any abnormal loss factors. ERCOT and TSPs shall use the cost of losses as one criterion in evaluating the need for transmission additions.

13.3 Distribution Losses

(1) By October 30th of each year for the next calendar year, or two months prior to the posting of any update to the approved Distribution loss coefficients, codes, or calculation, each Distribution Service Provider (DSP), except NOIEs, shall calculate and provide ERCOT the Annual Distribution loss coefficients to be applied to distribution voltage level Loads in its area of certification. ERCOT shall review and approve the DLF calculation methodology used by each DSP prior to use of the loss coefficients for settlement purposes. If the DLF calculation methodology does not conform with

ERCOT's interpretation of the Protocol criteria in this subsection, ERCOT will work with the Distribution Service Provider to correct the deficiency. Until deficiencies are resolved, the last approved Distribution loss coefficients and the calculation methodology will be posted, and the last approved Distribution loss coefficients shall be used for settlement. A DSP may only submit a change to the DLF calculation methodology annually or when a change in a DSP service area warrants an update to the approved DLF methodology based on the DSP internal evaluation.

(2) The DSP shall assign a Distribution loss code to each ESI ID. A maximum of five Distribution loss codes may be submitted for each DSP based upon ERCOT approved parameters, such as service voltages or number of transformations.

(3) The following standards will be used to identify the Distribution loss code applicable to each ESI ID:

- T = Transmission connected Customers (no Settlement Interval DLF applied)
- A through E = TDSP defined Customer segment(s)

(4) The DSPs, except NOIEs, are obligated to provide Distribution loss coefficients to ERCOT. ERCOT will post the Distribution loss coefficients and calculation methodology, for each DSP.

(5) Distribution loss information submitted by the DSP shall include:

(a) The annual Distribution loss coefficients (F_1, F_2, and F_3) for each Distribution loss code; and

(b) The methodology upon which the calculation of the coefficients (F_1, F_2, and F_3) was made.

13.3.1 Loss Factor Calculation

(1) ERCOT shall use the Distribution loss coefficients submitted by the DSP to calculate the Settlement Interval DLFs. Settlement Interval DLFs will be calculated from the data provided by DSPs as follows using the following equation:

$$SILF_i = F_1 * (SIEL_i/AAL) + F_2 + F_3 / (SIEL_i/AAL)$$

Variable	Unit	Description
i		interval
SILFi		Settlement Interval DLF
SIELi		Settlement Interval ERCOT System Load (forecasted or actual)
AAL		Annual Interval Average ERCOT System Load. The AAL is calculated using the total ERCOT Load stated in the most recent settlement during the period beginning on September 1 and ending August 31. ERCOT will provide the AAL to DSPs that are obligated to provide Distribution loss coefficients and calculation methodology to ERCOT, by September 15th of each year.
F_1, F_2, F_3		Distribution Loss coefficients determined by the Distribution Service Provider to allow calculation of its SILF from ERCOT System Load

(2) ERCOT shall use the deemed actual Settlement Interval DLFs calculated for each Settlement Interval of the Operating Day for settlement purposes.

13.3.2 Loss Monitoring

Distribution loss coefficients and the calculation methodology from which they are derived for all DSPs, except for NOIEs, will be submitted to ERCOT and will be subject to audit for accuracy and consistency of application.

13.4 Special Loss Calculations for Settlement and Analysis

13.4.1 Deemed Actual Transmission Losses for NOIEs

(1) All QSEs representing Load, including NOIEs, will be responsible for Transmission Losses allocated in the manner described in these Protocols. Those Entities using transmission tie line meters to determine Load will adjust the net meter readings to remove calculated Transmission Losses behind the meter in order to determine the Load responsibility of the Entity. ERCOT will provide to settlement the calculation of the losses behind the meters, for each interval, using actual system conditions for that interval.

(2) The deemed actual Transmission Losses for NOIEs shall be a linear interpolation or extrapolation between the monthly on-peak and the monthly off-peak NOIE TLFs corresponding to the actual NOIE metered Load in the interval.

(3) ERCOT shall calculate monthly NOIE TLFs corresponding to the on-peak and off-peak base case system loads during each of the subsequent 18 calendar months as the basis for the NOIE TLFs. NOIE monthly loss factors will be calculated in the same manner as the loss factors are calculated for the ERCOT-wide TLFs.

13.4.2 Deemed Actual Transmission Losses for UFE Analysis

(1) ERCOT shall adjust Net Generation data used for UFE analysis zones that contains Transmission Facilities behind any metering points to the ERCOT-wide TLF. This adjustment requires reducing the Net Generation by the calculated deemed actual MWh of Transmission Losses and adding back the ERCOT-wide TLF translated into a MWh value. ERCOT shall provide the calculation of the deemed actual Transmission Losses behind the UFE zonal meters, for each interval, to settlement using actual system conditions for that interval.

(2) The deemed actual Transmission Losses for UFE analysis zones shall be a linear interpolation or extrapolation between the monthly on-peak and the monthly off-peak UFE analysis zone TLFs corresponding to the actual UFE analysis zone metered Load in the interval.

(3) ERCOT shall calculate monthly UFE analysis zones TLFs corresponding to the on-peak and off-peak base case UFE zone system Loads during each of the subsequent 18 calendar months as the basis for the UFE analysis zone TLFs. UFE analysis zone monthly loss factors will be calculated in the same manner as the loss factors are calculated for the ERCOT-wide TLFs.

ERCOT Nodal Protocols

Section 14: State of Texas Renewable Energy Credit Trading Program

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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14 STATE OF TEXAS RENEWABLE ENERGY CREDIT TRADING PROGRAM

14.1 Overview

(1) On May 9, 2000, the Public Utility Commission of Texas (PUCT) appointed ERCOT as Program Administrator of the Renewable Energy Credits (REC) Trading Program described in paragraph (g) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

(2) The purposes of the REC Trading Program are:

(a) To ensure that the cumulative installed generating capacity from renewable energy technologies in this state totals 2,280 megawatts (MW) by January 1, 2007, 3,272 MW by January 1, 2009, 4,264 MW by January 1, 2011, 5,256 MW by January 1, 2013, and 5,880 MW by January 1, 2015, with a target of at least 500 MW of the total installed renewable capacity after September 1, 2005, coming from a renewable energy technology other than a source using wind energy, and that the means exist for the state to achieve a target of 10,000 MW of installed renewable capacity by January 1, 2025;

(b) To provide for a REC Trading Program by which the renewable energy requirements established by the Public Utility Regulatory Act (PURA) §39.904(a) may be achieved in the most efficient and economical manner; to encourage the development, construction, and operation of new renewable energy Resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial Resources; to protect and enhance the quality of the environment in Texas through increased use of renewable Resources; and

(c) To ensure that all Customers have access to providers of energy generated by renewable energy Resources pursuant to PURA §39.101(b)(3).

(3) ERCOT shall administer the REC Trading Program, which became effective July 1, 2001. Entities participating in the REC Trading Program must register with and execute the appropriate agreements with ERCOT.

14.2 Duties of ERCOT

As described in more detail in this Section, ERCOT shall:

(a) Register renewable energy generators;

(b) Register offset generators;

(c) Register Retail Entities;

(d) Register other Entities choosing to participate in the Renewable Energy Credit (REC) Trading Program;

(e) Create and maintain REC Accounts for REC Trading Program participants;

(f) Determine the annual Renewable Portfolio Standard (RPS) requirement for each Retail Entity in Texas using the formulas set forth in this Section;

(g) On a quarterly basis, award RECs or Compliance Premiums earned by REC generators based on verified MWh production data;

(h) Verify that Retail Entities meet annual REC compliance requirements;

(i) Retire RECs or Compliance Premiums as directed by REC Trading Program participants;

(j) Retire RECs or Compliance Premiums as they expire;

(k) On a monthly basis, make public the aggregated total MWh competitive energy sales in Texas;

(l) Make public a list of REC Account Holders with contact information (e-mail, address, and telephone number) so as to facilitate REC or Compliance Premium trading;

(m) Maintain a list of offset generators and the Retail Entities to whom such a generator's offsets were awarded by the Public Utility Commission of Texas (PUCT);

(n) Conduct a REC Trading Program Settlement process annually, starting in 2002 with voluntary Settlements for the Customer Choice pilot;

(o) File an annual report with the PUCT as specified in paragraph (g)(11) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy;

(p) Monitor the operational status of all existing renewable energy generation facilities in Texas and record retirements;

(q) Compute and apply a revised Capacity Conversion Factor (CCF) (as described in Section 14.9.2, Capacity Conversion Factor) every two years;

(r) Audit MWh production data from certified REC generating facilities;

(s) Audit MWh production from renewable energy generation facilities producing offsets for Retail Entities on an annual basis; and

(t) Post a list of Facility Identification Numbers, and the associated renewable energy generation facility name, location, type, and noncompetitive certification data on the Market Information System (MIS) Public Area.

14.2.1 Site Visits

ERCOT may conduct site visits to renewable energy generation facilities on a random basis to ensure integrity of the REC Trading Program, as deemed necessary. ERCOT shall require each registered renewable energy generator to provide one or more contact persons for purpose of site visit notification. ERCOT shall provide at least 48 hours notice to the designated contact(s) prior to conducting a site visit for wind Resources only.

14.3 Creation of Renewable Energy Credit Accounts and Attributes of Renewable Energy Credits

14.3.1 Creation of Renewable Energy Credit Accounts

ERCOT shall create Renewable Energy Credit (REC) accounts for any party desiring to participate in the REC Trading Program. ERCOT shall require all holders of REC Accounts to execute a standard Agreement with ERCOT. Each party requesting a REC Account must name a Designated Representative and may name an additional contact person. The Designated Representative must have the authority to represent and legally bind the owners and operators of the renewable Resource in all matters pertaining to the REC Trading Program. These individuals will be the contact persons for ERCOT on matters regarding a REC Account.

14.3.2 Attributes of Renewable Energy Credits and Compliance Premiums

(1) A REC or Compliance Premium is a tradable instrument that represents all of the renewable attributes associated with one MWh of production from a certified renewable generator. A REC or Compliance Premium may trade separately from energy. RECs are distributed to REC generators on a quarterly basis by ERCOT. The number of RECs distributed to a certified generator is based on physically metered MWh production. RECs may be traded, transferred, and retired.

(2) Compliance Premiums are awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy Resource that is not powered by wind and meets the criteria of paragraph (l) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. For the purpose of the Renewable Portfolio Standard (RPS) requirements, one Compliance Premium is equal to one REC.

REC Information	Field Length	Description
Year	4 Digits	Year REC was issued
Quarter	1 Digit	Quarter REC was issued
Type of Renewable Resource	2 Characters	Abbreviated reference to type of renewable Resource
Facility Identification Number	5 Digits	Number to be assigned by ERCOT

REC Number	8 Digits	REC Number 1 through the number of MWh generated by the Facility during the quarter.

(3) The Facility Identification Number assigned by ERCOT will be fixed for a facility's lifetime, and will therefore remain constant regardless of changes in facility name or ownership. Facilities must file changes of name, ownership, or other relevant certification information with ERCOT within 30 days of such changes.

(4) Generating facilities that lose their Public Utility Commission of Texas (PUCT) REC generator certification will not be awarded RECs by ERCOT subsequent to the date of the certification revocation, unless ERCOT is otherwise directed by the PUCT.

(5) A REC generated on or after January 1, 2002, will have an issue date of the Compliance Period in which it is generated.

(6) RECs have a useful life of three Compliance Periods. For example, a qualifying MWh of renewable energy generated on December 31, 2006 will be the basis for a REC having an issue date of 2006. The three Compliance Periods for which this REC may be used are 2006, 2007, and 2008. This REC will expire one Business Day after March 31, 2009. March 31 is the date by which a Retail Entity must submit its annual REC compliance retirement information to ERCOT.

14.4 Registration to Become a Renewable Energy Credit Generator or Renewable Energy Credit Aggregator

(1) Renewable Energy Credit (REC) generators or REC aggregators must apply to the Public Utility Commission of Texas (PUCT) for certification to produce or aggregate RECs. On receipt of a copy of a notification from the PUCT certifying that a renewable energy generation facility is eligible to generate or an Entity is eligible to aggregate RECs, ERCOT shall establish a REC Account for the facility or Entity. Each REC Account shall have a unique identification number.

(2) After providing 30 days notice to the REC Account Holder, ERCOT will close an account holding no RECs or Compliance Premiums for a period of one year.

14.5 Reporting Requirements

14.5.1 Renewable Energy Credit Generators and Renewable Energy Credit Offset Generators

(1) All Renewable Energy Credit (REC) generators and REC offset generators must report quarterly MWh production data to ERCOT no later than the 38th day after the last Operating Day of the quarter, in an electronic format prescribed by ERCOT. The reported MWh quantity shall be solely produced from, and attributable to, a renewable

generator as so designated by the Public Utility Commission of Texas (PUCT). Information relevant to quarterly reporting shall be handled in one of the following processes:

(a) Renewable Resource facilities located within ERCOT that have interval meters, pursuant to Section 10, Metering, and have interval metered generation data provided to ERCOT for energy Settlement will have the quarterly reporting function performed on their behalf by ERCOT using the Settlement Quality Meter Data extracted from the ERCOT Settlement system;

(b) REC aggregation companies shall report production from microgenerator renewable energy Resources that are not interval metered for energy Settlement, in accordance with the methodology approved by the PUCT for the purposes of measuring the REC production of such Resources, in the format prescribed by ERCOT, including applicable supporting documentation;

(c) All other REC generators, not specifically covered in items (a) and (b) above, must report Settlement quality MWh production data to ERCOT in a format and on a timeline prescribed by ERCOT; provided that REC generators not interconnected to any Transmission and/or Distribution Service Provider (TDSP) may use performance measures for REC production as approved by the PUCT; or

(d) Entities certified to produce RECs from landfill gas supplied directly to a gas distribution system operated by a Municipally Owned Utility (MOU) shall report, in writing, the MWh equivalent production data and supporting calculations to ERCOT on a timeline prescribed by ERCOT.

(2) From time to time, or as determined to be necessary by ERCOT or the PUCT, Entities may be required to submit supporting documentation to allow verification of generation quantities.

(3) The failure of a REC generator to report generation data in a timely fashion shall result in a delay in the issuance of RECs or Compliance Premiums for that generation facility for that quarter. RECs or Compliance Premiums delayed by untimely reporting will be awarded during the REC award period next occurring after the required data are reported. The issue date of such RECs or Compliance Premiums will be based on the quarter in which the RECs or Compliance Premiums were actually generated.

14.5.2 Retail Entities

(1) To enable Retail Entities the ability to calculate their Renewable Portfolio Standards (RPS) requirements, all Retail Entities serving Load in the state of Texas shall provide Load data to ERCOT on a monthly basis, and no later than the 38th day after the last Operating Day of the month, in an electronic format prescribed by ERCOT. The reported MWh quantity shall be solely the energy consumed by Customers in Texas. Load data shall be provided in one of the following processes:

(a) Retail Entities serving Load located within ERCOT shall have this function performed for them by ERCOT for the Load served within ERCOT. The data supplied by ERCOT shall be Settlement Quality Meter Data extracted from the ERCOT Settlement system; or

(b) Entities participating in the REC Trading Program that serve Load outside the ERCOT Region must report Settlement quality MWh Load data for Load served outside the ERCOT Region to ERCOT in a format prescribed by ERCOT. Notwithstanding the foregoing reporting requirements, such Entities shall submit monthly MWh Load data for December of each year by no later than January 15 of the following year. Any error in estimating December Load shall be corrected by the submitting entity in the following year's true-up calculation as per paragraph (h)(3) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy.

(2) On a monthly basis, ERCOT shall calculate the MWh consumption of energy by Customers served by Retail Entities in Texas, using Load data submitted by program participants.

(3) The failure of a Retail Entity to report required Load data in accordance with the Protocols shall result in estimation of Load data for the applicable Retail Entity by ERCOT for purposes of allocation of annual RPS requirements.

14.6 Awarding of Renewable Energy Credits

Following the end of each calendar quarter, and upon receipt of Renewable Energy Credit (REC) generator and Load data specified in Section 14.5.1, Renewable Energy Credit Generator and Renewable Energy Credit Offset Generators, and in Section 14.5.2, Retail Entities, ERCOT will credit RECs to the appropriate REC Account. ERCOT shall base the number of RECs to be issued on the MWh generation data provided by REC generators or ERCOT as applicable. The number of RECs issued to a specific REC generator will be equal to the number of MWh generated by the certified generator during the quarter. Quarterly production shall be rounded to the nearest whole MWh, with fractions of 0.5 MWh or greater rounded up. If a REC generator is decertified during the quarter, RECs will be issued on MWhs produced during the quarter until the date and time of decertification.

14.6.1 Adjustments to Renewable Energy Credit Award Calculations

Adjustments (reductions) to REC awards are made for renewable facilities that use more than 2% fossil fuel, renewable facilities that are repowered, and for REC aggregators that use estimation techniques to report generation.

(a) Co-Fired Generator Adjustments:

(i) For REC generators using a renewable energy technology that requires the use of fossil fuel that is greater than 2%, and less than or equal to 25%, of the total annual fuel input on a British Thermal Unit (BTU) or equivalent basis, RECs can only be earned on the renewable portion of the production. RECs are awarded based on an adjusted number of MWh generated during the quarter.

(ii) The renewable energy Resource shall calculate the electricity generated by the unit in MWh, based on the BTUs (or equivalent) produced by the fossil fuel and the efficiency of the renewable energy Resource, subtract the MWh generated with fossil fuel input from the total MWh of generation and report the renewable energy generated to the Program Administrator;

(b) Repowered Facility Adjustments:

(i) A Repowered Facility is eligible to earn RECs on all renewable energy produced up to a capacity of 150 MW. Capacity greater than 150 MW may earn RECs for the energy produced in proportion to 150 divided by nameplate capacity.

(ii) Repowered Facilities with a generation capacity greater than 150 MW will be awarded RECs based on an adjusted number of MWh generated during the quarter.

$$\textbf{AdjustedMWh} = \textbf{HO}_{q}\ \textbf{(150 / NC)}$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
HO_q	MWh	Total production or historical output by the Repowered Facility for quarter "q"
NC	None	Nameplate capacity is the machine generation capacity posted on a specific piece of equipment or unit

(c) REC Aggregator Adjustments:

The REC aggregator may provide the Program Administrator with sufficient information for the Program Administrator to estimate with reasonable accuracy the output of each unit, based on known or observed information that correlates closely with the generation output. REC aggregators using approved estimation techniques to report renewable energy production shall be awarded one REC for every 1.25 MWh generated.

14.6.2 Awarding of Compliance Premiums

(1) A Compliance Premium is awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy Resource installed and certified after

September 1, 2005 that is not powered by wind. For the purpose of the Renewable Portfolio Standards (RPS) requirements, one Compliance Premium is equal to one REC.

(2) One Compliance Premium shall be awarded for each REC awarded for energy generated after December 31, 2007.

14.7 Transfer of Renewable Energy Credits or Compliance Premiums Between Parties

(1) On the receipt of a request from the owner of a Renewable Energy Credit (REC) or Compliance Premium and purchaser of the REC or Compliance Premium, ERCOT will transfer the REC or Compliance Premium from the owner’s REC Account to the REC Account specified in the transfer request. Transfer requests received by ERCOT and confirmed by both Entities by 1000 shall be effective the next Business Day.

(2) If a request for transfer cannot be executed, ERCOT will notify the requesting Entities of the reason.

(3) On completing a transfer, ERCOT shall notify the Designated Representatives of all involved REC Account owners by e-mail.

(4) For the purpose of the REC Trading Program, RECs or Compliance Premiums residing in an Entity’s REC Account are deemed to be owned by that Entity.

(5) To the extent practicable, ERCOT will accommodate automated quarterly transfers.

14.8 Renewable Energy Credit Offsets

(1) To qualify for Renewable Energy Credit (REC) offsets in the REC Trading Program, a Retail Electric Provider (REP), Municipally Owned Utility (MOU), generation and transmission cooperative, distribution cooperative, or an affiliate of a REP, MOU, generation and transmission cooperative, or distribution cooperative must apply for REC offsets from the Public Utility Commission of Texas (PUCT) by June 1, 2001. This requirement is in effect without regard to whether or not the applicant will be a Retail Entity on January 1, 2002. A REC offset represents one MWh of renewable energy from a renewable energy generator placed in service before September 1, 1999 that may be used in place of a REC to meet a renewable energy requirement. REC offsets may not be traded.

(2) After receipt of notification from the PUCT (which shall include the name of the Entity receiving the offset, the name of the generator eligible to produce the offset, the value of the offset in MWh, and other information as applicable) verifying designation by the Entity receiving REC offsets, ERCOT shall use REC offsets from a Retail Entity as part of its calculation of final RPS requirements. REC offsets are not transferable. REC offsets will be considered valid until ERCOT receives notification from the PUCT that the offset is no longer valid.

(3) For purposes of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, a generation and transmission cooperative shall be responsible for the cumulative total of its cooperative members' renewable energy requirements as well as its affiliated cooperative members' renewable energy requirements. At the election of its board of directors, a generation and transmission cooperative will become responsible for the cumulative total of its distribution cooperatives' Renewable Portfolio Standards (RPS) requirements. The sharing of the REC offsets of the generation and transmission cooperative among its distribution cooperatives shall not affect the cumulative total of the RPS requirements of the distribution cooperative members, or its affiliated cooperative members in meeting their share of the state's goals for renewable energy Resources.

14.9 Allocation of Statewide Renewable Portfolio Standard Requirement Among Retail Entities

Beginning with the 2002 Compliance Period, and every Compliance Period thereafter through 2020, the first quarter of each year shall be the Settlement period for the preceding Compliance Period. During this Settlement period each year the following actions shall occur:

(a) No later than the date set forth in P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, the Program Administrator shall allocate the statewide Renewable Portfolio Standards (RPS) requirement for the previous year's Compliance Period among all Retail Entities in the state. This allocation represents the Renewable Energy Credit (REC) compliance requirements for the preceding Compliance Period. To perform this calculation, ERCOT shall use Load data provided to it as set forth in these Protocols.

(b) By the date set forth in P.U.C. SUBST. R. 25.173, the Program Administrator shall notify each Retail Entity of its total final adjusted RPS requirement for the previous Compliance Period.

(c) By the date set forth in P.U.C. SUBST. R. 25.173, each Retail Entity must submit to the Program Administrator RECs from its REC Account equivalent to its final adjusted RPS requirement for the previous Compliance Period.

(d) The Program Administrator may request from the Public Utility Commission of Texas (PUCT) an adjustment to the deadlines set forth in this Section if certain factors, including but not limited to changes to the ERCOT Settlement Calendar, should affect the timely availability of reliable retail sales data or renewable Resource generation data necessary for calculating RPS requirements.

14.9.1 Annual Capacity Targets

(1) The renewable energy capacity targets (in megawatts) for each year are as follows:

Annual Capacity Target (MW)	Existing Renewable Capacity (MW)	Total Renewable Capacity Target (MW)	Compliance Period (Years)
400	880	1280	2002, 2003
850	880	1730	2004, 2005
1400	880	2280	2006, 2007
2392	880	3272	2008, 2009
3384	880	4264	2010, 2011
4376	880	5256	2012, 2013
5000	880	5880	2014, and each year after 2014

(2) ERCOT shall increase the new renewable energy capacity target for all future Compliance Periods to account for:

(a) Capacity producing RECs from eligible qualifying out-of-state facilities metered in Texas; and

(b) Capacity from a renewable energy generator placed in service before September 1, 1999 that has been retired or otherwise removed from the program and results in a statewide existing renewable capacity of less than 880 MW.

ERCOT shall apply any such changes for out-of-state capacity and retirements at such time the revised Capacity Conversion Factor (CCF) is computed and applied.

(3) RECs may be produced by generators certified by the PUCT which are not located in Texas if:

(a) The first metering point for such generation is in Texas; and

(b) All generation metered at the location of injection into the Texas grid comes from that generator.

(4) REC generators physically located outside the state of Texas are not included in the annual calculations of installed renewable capacity for purposes of the REC Trading Program. However, as such generation may contribute to the available pool of RECs, it is conceivable that there may be sufficient RECs to allow Retail Entities to meet their annual requirements, while at the same time, a target capacity shortfall for installed renewable capacity in Texas could exist.

14.9.2 Capacity Conversion Factor

(1) ERCOT shall set the CCF to allocate credits to Retail Entities. The CCF shall be calculated during the fourth quarter of each odd numbered compliance year. ERCOT shall determine a new CCF as follows:

$$\textbf{Individual Facility CCF}_{\,i} = \mathbf{(12/n)*} \sum_{t=1}^{n} \mathbf{HO}_{\,i,\,t} \mathbf{\;/\;(HC}_{\,i,\,t}\mathbf{\,*\,8760)}$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	Individual renewable energy generation facility
n	None	Number of months a specific renewable energy generation facility was in operation over the past 24 months. *n* must be greater than or equal to 12 and less than or equal to 24.
$HO_{i,\,t}$	MWh	Total production by participating renewable generator *i* during Compliance Period *t*.
$HC_{i,\,t}$	MW	Average total generation capacity by participating renewable generator *i* during Compliance Period *t*.

and

$$\mathbf{CCF} = \sum_{i-1}^{q} \mathbf{(CCF}_{\,i}\mathbf{\,*\,PC}_{\,i}\mathbf{)\;/} \sum_{i-1}^{q} \mathbf{PC}_{\,i}$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	The total number of renewable energy generation facilities in the REC Trading Program
PC_{i}	MW	Participating Capacity as of September 30 of the year the revised CCF is calculated for renewable energy generation facility *i* in the state of Texas participating in the REC Trading Program for which at least 12 months of operating data are available.

(2) The CCF shall:

(a) Be based on actual generator performance data for the previous two years for all renewable Resources in the REC Trading Program during that period for which at least 12 months of performance data are available;

(b) Represent a weighted average of generator performance; and

(c) Use all actual generator performance data that are available for each renewable Resource, excluding data for testing periods.

(3) For purposes of calculating historical output from renewable capacity, ERCOT shall keep a list of renewable generators, REC certification dates, and annual MWh generation totals.

(4) ERCOT shall use this revised CCF for the two Compliance Periods immediately after it is set. If the PUCT has determined that the REC Trading Program is failing to meet the statutory targets for renewable energy capacity in Texas, it will instruct ERCOT to use a different number than that which would be calculated using the formula for the CCF. Such requests will be published on the ERCOT Market Information System (MIS) Public Area within ten Business Days of receipt of the letter from the PUCT.

14.9.3 Statewide Renewable Portfolio Standard Requirement

ERCOT shall determine the Statewide RPS Requirement for a particular Compliance Period as follows:

Statewide RPS Requirement (SRR) = (ACT ∗ 8760 ∗ CCF) + RCP

The above variables are defined as follows:

Variable	Unit	Description
ACT	MW	Annual Capacity Target for new renewable energy generation facilities.
8760	None	The number of hours in a year.
CCF	None	Capacity Conversion Factor.
RCP	None	The number of Compliance Premiums retired during the previous Compliance Period.

14.9.3.1 Preliminary Renewable Portfolio Standard Allocation for Retail Entities

(1) ERCOT shall determine each Retail Entity’s preliminary RPS allocation as follows:

$$\mathbf{PRR}_{i} = \mathbf{SRR\ (MWh) * (RES}_{i}\ \mathbf{(MWh) / TS\ (MWh))}$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	Specific Retail Entity.
SRR	None	Statewide RPS requirement.
$CRSRES_i$	MWh	Retail sales of the specific Retail Entity to Texas Customers during the Compliance Period.
TS	MWh	Total retail sales of all Retail Entities to Texas Customers during the Compliance Period.

(2) The sum of the preliminary RPS requirements for all Retail Entities shall be equal to the statewide RPS requirement.

14.9.4 Application of Offsets - Adjusted Renewable Portfolio Standard Allocation

(1) Retail Entity that has been awarded offsets by the PUCT, ERCOT shall subtract the REC offset amount from the preliminary RPS allocation. The reduction shall not exceed what would be necessary or the final RPS requirement to be zero. The total MWh reduction in the preliminary RPS allocation for all Retail Entities constitutes Total Useable Offsets (TUOs).

(2) ERCOT shall determine each Retail Entity's adjusted RPS allocation as follows:

$$\mathbf{ARR}_{\boldsymbol{i}} = \mathbf{PRR}_{\boldsymbol{i}} - \mathbf{EO}_{\boldsymbol{i}}$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	Specific Retail Entity.
PRR_i	None	Preliminary RPS allocation for a specific Retail Entity.
EO_i	None	Total offsets the Retail Entity is entitled to receive during the Compliance Period (not to exceed the Retail Entity's final RPS allocation before adjustment for any previous Compliance Period.)

(3) ERCOT shall determine TUOs as follows:

$$\mathbf{TUO} = \mathbf{SRR} - \sum_{i=1}^{n} \mathbf{ARR}_{\boldsymbol{i}}$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	Specific Retail Entity.
n	None	Number of Retail Entities.
SRR	None	Statewide RPS requirement.
ARR_i	None	Adjusted RPS allocation for a specific Retail Entity.

14.9.5 Final Renewable Portfolio Standard requirement

(1) ERCOT shall redistribute the TUO amount over all Retail Entities to determine the final RPS requirements. ERCOT shall determine each Retail Entity's final RPS requirement as follows:

Final RPS Requirement = ARR $_i$ + (TUO × (RES $_i$ / TS)) +/- Previous Year(s) final RPS requirement adjustment (recalculated in accordance with paragraph (h)(3) of P.U.C. SUBST. R. 25.173)

The above variables are defined as follows:

Variable	Unit	Description
ARR_i	None	Adjusted RPS allocation for a specific Retail Entity.
TUO	None	Total Usable Offsets.
$CRSRES_i$	MWh	Retail sales of the Retail Entity to Texas Customers during the Compliance Period.
TS	MWh	Total retail sales of all Retail Entities to Texas Customers during the Compliance Period.

(2) This process will be an iterative process that will solve until the optimal allocation is reached with all final RPS requirements resolved to the nearest whole REC.

(3) ERCOT shall notify each Retail Entity of its final RPS allocation for the previous Compliance Period no later than the date set forth for such Notification in paragraph (m)(l) of P.U.C. SUBST. R. 25.173.

14.10 Retiring of Renewable Energy Credits or Compliance Premiums

A Renewable Energy Credit (REC) or Compliance Premium owner's Designated Representative must submit retirement requests to ERCOT. RECs or Compliance Premiums specified by a Designated Representative for retirement must be in the REC Account from which they are being retired at the time the request is submitted. ERCOT shall retire such RECs or Compliance Premiums by removing them from the party's REC Account and retiring the unique serial number, thus rendering the REC or Compliance Premium unusable for any other purpose. ERCOT shall maintain records to archive all RECs or Compliance Premiums that have been retired and to identify the basis on which RECs or Compliance Premiums were retired. The reasons for retiring RECs include mandatory compliance, voluntary retirement, and expiration. The reasons for retiring Compliance Premiums include mandatory compliance, voluntary retirement, and expiration.

14.10.1 Mandatory Retirement

(1) For each Compliance Period, beginning with the 2002 Compliance Period, by the date set forth for such notification in paragraph (m)(2) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy, each Retail Entity's Designated Representative shall notify ERCOT

of the RECs or Compliance Premiums in its REC Account to be used (retired) to satisfy its final RPS requirement for the Compliance Period being settled. Each REC or Compliance Premium that is not used will remain in the holder's REC Account until it is transferred to another party's account, expires, or is otherwise retired.

(2) Failure to provide sufficient RECs or Compliance Premiums shall be considered a failure of that Retail Entity to meet its REC retirement obligations. ERCOT shall notify the Public Utility Commission of Texas (PUCT) when any Retail Entity fails to meets its REC retirement obligations.

14.10.2 Voluntary Retirement

At the request of a REC Account Holder, ERCOT shall retire RECs and Compliance Premiums for reasons other than for meeting the mandated Renewable Portfolio Standards (RPS) requirements. Voluntarily retired RECs and Compliance Premiums may not be used to satisfy a Retail Entity's RPS requirement. ERCOT shall include information concerning RECs and Compliance Premiums retired voluntarily in its annual report to the PUCT.

14.10.3 Retiring Unused Renewable Energy Credits or Compliance Premiums

ERCOT shall retire all unused RECs and Compliance Premiums upon their expiration as described in Section 14.3.2, Attributes of Renewable Energy Credits and Compliance Premiums.

14.11 Penalties and Enforcement

ERCOT is not responsible for developing, administering, or enforcing penalties associated with the Renewable Energy Credit (REC) Trading Program; these activities are within the scope of the Public Utility Commission of Texas (PUCT). ERCOT is responsible for informing the PUCT of Retail Entities that do not meet their REC or Compliance Premium retirement obligations, of REC offset generators that do not produce generation sufficient to cover offsets they have been approved to provide, and of other anomalies which may come to ERCOT's attention through the administration of the REC Trading Program.

14.12 Maintain Public Information

(1) ERCOT shall maintain public information of interest to buyers and sellers of Renewable Energy Credits (RECs) or Compliance Premiums on the ERCOT Market Information System (MIS) Public Area. The information provided shall include, at a minimum, a directory of all REC generators, Retail Entities, and other participants in the REC Trading Program. The directory shall include the following information:

(a) Name of the REC generator, Retail Entity, or other REC Account Holder;

(b) Name of the Designated Representative;

(c) Street address or post office box number;

(d) City, state or province, and ZIP or postal code;

(e) Country (if not the United States);

(f) Phone number;

(g) Fax number;

(h) E-mail address (with hypertext link); and

(i) Web site address (with hypertext link).

(2) REC Account Holders shall describe their participation in the REC Trading Program using one or more of the following choices within a checkbox listing: REC generator, Retail Entity, REC broker, REC trader, REC trading exchange, REC aggregation company, or other.

(3) Entities are responsible for notifying ERCOT of changes in the above information.

(4) ERCOT shall conspicuously display the following disclaimer in upper case and in bold font:

DISCLAIMER: ERCOT DOES NOT KNOW OR ENDORSE THE CREDIT WORTHINESS OR REPUTATION OF ANY REC ACCOUNT HOLDER LISTED IN THIS DIRECTORY.

(5) ERCOT may provide other information that describes the REC Trading Program, as it deems convenient or necessary for administering the REC Trading Program. ERCOT shall maintain a hypertext link to the appropriate pages on the Public Utility Commission of Texas' (PUCT) web site that are related to the REC Trading Program.

(6) ERCOT shall post each month the best available aggregated total energy sales (in MWh) of Retail Entities in Texas for the previous month and year-to-date for the calendar year.

(7) ERCOT shall post a list of Facility Identification Numbers, associated names, locations, and types.

14.13 Submit Annual Report to Public Utility Commission of Texas

Beginning in 2002, ERCOT shall submit an annual report to the Public Utility Commission of Texas (PUCT) on or before the date set forth for such report in paragraph (g)(11) of P.U.C. SUBST. R. 25.173, Goal for Renewable Energy. Such report shall contain the following information pertaining to program operation for the previous Compliance Period:

(a) MW of existing renewable capacity installed in Texas, by technology type;

(b) MW of new renewable energy capacity installed in Texas, by technology type;

(c) List of eligible non-Texas capacity participating in the program, by technology type;

(d) Summary of Renewable Energy Credit (REC) aggregation company activities, submitted in a format specified by the PUCT;

(e) Owner/operator of each REC generating facility;

(f) Date each new renewable energy facility began to produce energy;

(g) MWh of energy generated by renewable energy Resources as demonstrated through data supplied in accordance with these Protocols;

(h) List of renewable energy unit retirements;

(i) List of all Retail Entities participating in the REC Trading Program;

(j) Final Renewable Portfolio Standards (RPS) allocation of each Retail Entity;

(k) Number of REC offsets used by each Retail Entity;

(l) A list of REC offset generators, REC offsets awarded and MWh production from each such generator on an annual basis;

(m) Number of RECs retired by each program participant by category (mandatory compliance, voluntary retirement, expiration, and total retirements);

(n) Number of Compliance Premiums retired by each program participant by category (mandatory compliance, expiration, and total retirements);

(o) List of all Retail Entities in compliance with RPS requirement; and

(p) List of all Retail Entities not in compliance with RPS requirement including the number of RECs by which they were deficient.

ERCOT Nodal Protocols

Section 16: Registration and Qualification of Market Participants

Updated: August 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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16 REGISTRATION AND QUALIFICATION OF MARKET PARTICIPANTS

16.1 Qualification, Registration, and Execution of Agreements

(1) ERCOT shall require each Market Participant to register and execute the Standard Form Market Participant Agreement and, as applicable, Reliability Must-Run Agreement; and Black Start Agreement.

(2) A Standard Form Market Participant Agreement is in Section 22, Agreements, and ERCOT shall also post this agreement on the Market Information System (MIS) Public Area.

(3) ERCOT shall post on the MIS Public Area all registration procedures and applications necessary to complete registration for any function described in these Protocols. As part of its registration procedures, ERCOT may require one or more of the following:

(a) Reasonable tests of the ability of a Market Participant to communicate with ERCOT or perform as required under these Protocols;

(b) An application fee as determined by the ERCOT Board; and

(c) Related agreements for specific purposes (such as agency designation, meter splitting, or network interconnection) that apply only to some Market Participants.

16.2 Registration and Qualification of Qualified Scheduling Entities

16.2.1 Criteria for Qualification as a Qualified Scheduling Entity

(1) To become and remain a QSE, an Entity must meet the following requirements:

(a) Submit a properly completed QSE application for qualification, including any applicable fee and including designation of Authorized Representatives, each of whom is responsible for administrative communications with the QSE and each of whom has enough authority to commit and bind the QSE and the Entities it represents;

(b) Sign a Standard Form Market Participant Agreement;

(c) Sign any required Agreements relating to use of the ERCOT network, software, and systems;

(d) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of performing the functions of a QSE;

(e) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of complying with the requirements of all ERCOT Protocols and Operating Guides;

(f) Satisfy ERCOT's creditworthiness requirements as set forth in this Section;

(g) Be generally able to pay its debts as they come due; ERCOT may request evidence of compliance with this qualification only if ERCOT reasonably believes that a QSE is failing to comply with it;

(h) Provide all necessary bank account information and arrange for Fedwire system transfers for two-way confirmation;

(i) Be financially responsible for payment of settlement charges for those Entities it represents under these Protocols;

(j) Comply with the backup plan requirements in the Operating Guides;

(k) Maintain a 24-hour, seven-day-per-week scheduling center with qualified personnel for the purposes of communicating with ERCOT for scheduling and deploying the QSE's Ancillary Services in Real-Time. Those personnel must be responsible for operational communications and must have sufficient authority to commit and bind the QSE and the Entities that it represents;

(l) Demonstrate and maintain a working functional interface with all required ERCOT computer systems; and

(m) Allow ERCOT, upon reasonable notice, to conduct a site visit to verify information provided by the QSE.

(2) If a QSE chooses to use electronic data interchange (EDI) transactions to receive Settlement Statements and Invoices, it must participate in and successfully complete testing as described in Section 23, Texas Test Plan Team - Retail Market Testing, before starting operations with ERCOT as a QSE.

(3) A QSE shall promptly notify ERCOT of any change that materially affects the Entity's ability to satisfy the criteria set forth above, and of any material change in the information provided by the QSE to ERCOT that may adversely affect the reliability or safety of the ERCOT System or the financial security of ERCOT. If the QSE fails to so notify ERCOT within one day after the change, then ERCOT may, after providing notice to each Entity represented by the QSE, refuse to allow the QSE to perform as a QSE and may take any other action ERCOT deems appropriate, in its sole discretion, to prevent ERCOT or Market Participants from bearing potential or actual risks, financial or otherwise, arising from those changes, and in accordance with these Protocols.

(4) Subject to the following provisions of this item (4), a QSE may partition itself into any number of subordinate QSEs ("Subordinate QSEs"). If a single Entity requests to partition itself into more than four Subordinate QSEs, ERCOT may implement the request subject to ERCOT's reasonable determination that the additional requested Subordinate QSEs will not be likely to overburden ERCOT's staffing or systems. ERCOT shall adopt an implementation plan allowing phased-in registration for these

additional Subordinate QSEs in order to mitigate system or staffing impacts. However, ERCOT may not unreasonably delay that registration.

(5) Each Subordinate QSE must be treated as an individual QSE for all purposes including communications and control functions except for liability, financial security, and financial liability requirements under this Section. That liability, financial security, and financial liability is cumulative for all Subordinate QSEs for the single Entity signing the QSE Agreement.

(6) Continued qualification as a QSE is contingent upon compliance with all applicable requirements in these Protocols. ERCOT may suspend a QSE's rights as a Market Participant when ERCOT reasonably determines that it is an appropriate remedy for the Entity's failure to satisfy any applicable requirement.

16.2.2 QSE Application Process

To register as a QSE, an applicant must submit to ERCOT a completed QSE application and any applicable fee. ERCOT shall post on the MIS Public Area the form in which QSE applications must be submitted, all materials that must be provided with the QSE application and the fee schedule, if any, applicable to QSE applications. The QSE application shall be attested to by a duly authorized officer or agent of the applicant. The QSE applicant shall promptly notify ERCOT of any material changes affecting a pending application using the appropriate form posted on the MIS Public Area. The application must be submitted at least 60 days before the proposed date of commencement of service.

16.2.2.1 Notice of Receipt of Qualified Scheduling Entity Application

Within three Business Days after receiving a QSE application, ERCOT shall issue to the applicant a written confirmation that ERCOT has received the QSE application. ERCOT shall return without review any QSE application that does not include the proper application fee. The remainder of this Section does not apply to any QSE application returned for failure to include the proper application fee.

16.2.2.2 Incomplete Applications

(1) Within ten Business Days after receiving a QSE application, ERCOT shall notify the applicant in writing if the application is incomplete. If ERCOT fails to notify the applicant that the application is incomplete within ten Business Days, then the application is considered complete as of the date ERCOT received it.

(2) If a QSE application is incomplete, ERCOT's notice of incompletion to the applicant must explain the deficiencies and describe the additional information necessary to make the QSE application complete. The QSE applicant has five Business Days after it receives the notice, or a longer period if ERCOT allows, to provide the additional required information. If the applicant responds to the notice within the allotted time, then

the QSE application is considered complete on the date that ERCOT received the complete additional information from the applicant.

(3) If the applicant does not respond to the incompletion notice within the time allotted, ERCOT shall reject the application and shall notify the applicant using the procedures below.

16.2.2.3 ERCOT Approval or Rejection of Qualified Scheduling Entity Application

(1) ERCOT may reject a QSE application within ten Business Days after the application has been deemed complete in accordance with this Section. If ERCOT does not reject the QSE application within ten Business days after the application is deemed complete then the application is deemed approved.

(2) If ERCOT rejects a QSE application, ERCOT shall send the applicant a rejection letter explaining the grounds upon which ERCOT rejected the QSE application. Appropriate grounds for rejecting a QSE application include the following:

(a) Required information is not provided to ERCOT in the allotted time;

(b) Noncompliance with technical requirements; and

(c) Noncompliance with other specific eligibility requirements in this Section or in any other Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the QSE applicant may challenge the rejection of its QSE application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new QSE application and fee at any time, and ERCOT shall process the new QSE application under this Section.

(4) If ERCOT does not reject the QSE application within ten Business Days after the application has been deemed complete under this Section, ERCOT shall send the applicant, a Standard Form Market Participant Agreement and any other required agreements relating to use of the ERCOT network, software, and systems for the applicant's signature.

16.2.3 Remaining Steps for Qualified Scheduling Entity Registration

After a QSE application is deemed approved under Section 16.2.2.3, ERCOT Approval or Rejection of Qualified Scheduling Entity Application, the applicant shall coordinate or perform the following:

(a) Return the signed Standard Form Market Participant Agreement and other related agreements to ERCOT;

(b) Coordinate with ERCOT and other Entities, as necessary, to test all communications necessary to participate in the market in the ERCOT Region;

(c) Submit a Service Filing; and

(d) Demonstrate compliance with security and financial requirements.

16.2.3.1 Qualified Scheduling Entity Service Filing

(1) Not less than 15 days before starting any QSE activities with ERCOT, each QSE shall submit a complete "Service Filing," which includes a QSE Registration Form and a declaration on any Subordinate QSEs. ERCOT shall post on the MIS Public Area the forms and procedures to be used by a QSE to submit Service Filings. The Service Filing must include the following:

(a) Proof of credit for ERCOT security amount, as detailed below; the security amount must increase or decrease as the number of represented Market Participants and their respective market activities change;

(b) A complete list of all Market Participants that the QSE intends to represent; the list may be updated only until, but not within, the three days before the QSE starts providing QSE services; and,

(c) The date upon which the QSE proposes to start QSE activities with ERCOT.

(2) Not more than three Business Days after receiving each Service Filing, ERCOT shall send a written notice to the QSE that it has received the Service Filing. If the Service Filing is not complete, ERCOT shall notify the QSE by telephone or by written notice with an explanation of the additional information necessary to complete the Service Filing.

(3) Not more than ten days after a complete Service Filing (either a filing that is initially complete or one that has been supplemented under the above procedures) is received by ERCOT, ERCOT shall either notify the QSE that it may begin QSE activities upon its proposed start date or that the QSE's Service Filing is insufficient.

(4) Not later than ten Business Days after receiving a notice of insufficiency, the QSE may challenge the notice of insufficiency using the dispute resolution procedures in Section 20, Alternative Dispute Resolution Procedure. The QSE may submit a new Service Filing, and ERCOT shall process the new Service Filing under this Section.

16.2.3.2 Process to Gain Approval to Follow DSR Load

(1) Each QSE wanting to use Resources to follow DSR Load shall submit a proposal to ERCOT for analysis of the feasibility and reliability of the telemetry required by the

proposal. ERCOT shall either approve or disapprove that proposal based on ERCOT's ability to monitor the DSR Load behavior.

(2) Each DSR Load must be associated with a Load meter or group of Load meters. This includes Load that is calculated by subtracting interchange telemetry from actual generation telemetry, appropriately adjusted for Transmission and Distribution Losses.

16.2.3.3 Maintaining and Updating QSE Information

Each QSE must timely update information the QSE provided to ERCOT in the application process, and a QSE must promptly respond to any reasonable request by ERCOT for updated information regarding the QSE or the information provided to ERCOT by the QSE, including:

(a) The QSE's addresses;

(b) A list of Affiliates; and

(c) Designation of the QSE's officers, directors, Authorized Representatives, Credit Contacts, and User Security Administrator (all per the QSE application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

16.2.3.4 Qualified Scheduling Entity Service Termination

(1) If a QSE intends to terminate representation of an LSE or Resource (other than an LSE or Resource serving as its own QSE, in which case this Section does not apply), the QSE shall provide, no less than 12 Business Days before the specified effective termination date ("Termination Date"), written notice to ERCOT and the LSE or Resource.

(2) Effective at 2400 on the Termination Date specified by the QSE, the QSE may no longer provide QSE services for or represent the terminated LSE or Resource. The QSE is responsible for settlement obligations that the QSE has incurred on behalf of the terminated LSE or Resource before the termination. The QSE must participate in Real-Time Operations through the Termination Date and provide updates pursuant to these Protocols for the Operating Day which is the Termination Date. Notwithstanding the foregoing, if, before the Termination Date, the LSE/Resource:

(a) Affiliates itself with a new QSE, or

(b) Fulfills ERCOT's creditworthiness requirements in order to become an Emergency QSE,

the QSE that provided notice of the intent to terminate representation of the LSE/ Resource will no longer be responsible for the terminated LSE/Resource upon the effective date of the new QSE's representation of that LSE/Resource, or the LSE/Resource qualifying as an Emergency QSE.

(3) Within two Business Days of notice of a QSE's intent to terminate representation of an LSE, ERCOT shall notify the LSE of the level of credit the LSE must provide, if it becomes an Emergency QSE, and the date by which it must post the required collateral.

16.2.4 Posting of Qualified Scheduling Entity List

ERCOT shall post on the MIS Public Area and maintain a current list of all QSEs. ERCOT shall include with that posting a cautionary statement that inclusion on that list does not necessarily mean that a QSE is entitled to provide any service to a third party, nor does it obligate a QSE to provide any service to a third party.

16.2.5 Suspended Qualified Scheduling Entity – Notification to LSEs and Resource Entities Represented

(1) If a QSE can no longer act as a QSE, or if ERCOT suspends the QSE or terminates the Standard Form Market Participant Agreement, ERCOT shall notify the affected LSE's and Resource Entities that the QSE has been suspended and the effective date of such suspension.

(2) If an LSE or Resource Entity represented by the failed or suspended QSE is the same Entity as the failed or suspended QSE, the provisions of Section 16.11.6.1.6, Revocation of a Market Participant's Rights and Termination of Agreements, shall apply to that LSE or Resource Entity, and that LSE or Resource Entity shall not be entitled to become an Emergency QSE.

16.2.6 Emergency Qualified Scheduling Entity

16.2.6.1 Designation as an Emergency Qualified Scheduling Entity or Virtual Qualified Scheduling Entity

(1) A "Virtual QSE" is defined as an LSE or Resource Entity whose QSE has provided notice of its intent to terminate its relationship with the LSE and who has not met ERCOT's creditworthiness requirements to become an Emergency QSE, as set forth in this Section.

(2) If a QSE has given Notice of its intent to terminate its relationship with an LSE or Resource Entity, that LSE or Resource Entity, must, by noon on the fourth Business Day after the termination notice date, either

(a) Designate a new QSE with such relationship to take effect on the Termination Date, or earlier if allowed by ERCOT; or

(b) Satisfy all necessary creditworthiness requirements for QSEs as described in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

(3) If ERCOT has given Notice of an LSE's or Resource Entity's QSE's suspension, that LSE or Resource Entity will be designated as a Virtual QSE for up to two Bank Business Days, during which time it must either

(a) Designate and begin operations with a new QSE; or

(b) Satisfy all necessary creditworthiness requirements for QSEs as described in Section 16.2, and operate as an Emergency QSE as described below.

(4) If an LSE or Resource Entity meets the creditworthiness requirements, the LSE or Resource Entity may be designated as an Emergency QSE and may, upon the Termination Date, be issued digital certificates and given access to the MIS as determined by ERCOT.

(5) If the LSE fails to meet the requirements of one of the above options in the timeframe set forth above, ERCOT shall, after notice to the LSE and the PUCT, initiate a Mass Transition of the LSE's ESI IDs pursuant to Section 15.1.2.9, Mass Transition.

(6) If a Resource Entity fails to meet the requirements of one of the options set forth in paragraph (1) or (2) above within the requisite timeframe, ERCOT may allow the Resource Entity additional time, as determined by ERCOT staff, to meet the requirements.

(7) For any Operating Day in which an LSE or Resource Entity is not either represented by a QSE or qualified as an Emergency QSE, ERCOT may designate the LSE or Resource Entity as a Virtual QSE. ERCOT may issue digital certificates to the Virtual QSE for access to the capabilities of the MIS. A Virtual QSE shall be liable for any and all charges associated with Initial, Final and True-Up Settlements as well as any Resettlements applying to dates during which the Virtual QSE represented ESI IDs or otherwise incurred charges pursuant to these Protocols, along with any and all costs incurred by ERCOT in collecting such amounts.

(8) ERCOT shall maintain a referral list of qualified QSEs on the MIS Public Area who request to be listed as providing QSE services on short notice. The list shall include the QSE's name, contact information and whether they are qualified to represent Load and/or Resources and/or provide Ancillary Services. ERCOT shall not be obligated to verify the abilities of any QSE so listed. ERCOT shall require all QSEs listed to confirm their inclusion on the referral list no later than the start of each calendar year.

16.2.6.2 Market Participation by an Emergency Qualified Scheduling Entity or a Virtual Qualified Scheduling Entity

(1) An Emergency QSE or a Virtual QSE may only represent itself and may only submit:

(a) Energy Trades in which the Emergency QSE or the Virtual QSE is the buyer;

(b) Capacity Trades in which the Emergency QSE or the Virtual QSE is the buyer;

(c) Ancillary Service Trades in which the Emergency QSE or the Virtual QSE is the buyer; and

(2) An Emergency or Virtual QSE may submit DAM Energy Bids.

(3) An Emergency QSE or a Virtual QSE may submit those transactions described in paragraph (1) or (2) above, only to the extent that they are intended to serve the Load of the Emergency QSE's or Virtual QSE's Customers. If a Resource Entity, may submit transactions described in item (1) or (2) above only to the extent that those transactions are wholly provided by the Resource Entity's Resource(s).

16.2.6.3 Requirement to Obtain New Qualified Scheduling Entity or Qualified Scheduling Entity Qualification

(1) Within seven Business Days after receiving designation as an Emergency QSE, an Emergency QSE must either:

(a) Designate a QSE that will represent the LSE or Resource Entity to ERCOT or

(b) Fulfill all QSE registration and qualification requirements. After completing the requirements in item (b), ERCOT may redesignate the Emergency QSE as a QSE.

(2) If an Emergency QSE that is an LSE fails to meet at least one of the requirements listed above within the allotted time, then ERCOT shall, after notice to the Emergency QSE and the PUCT, initiate a Mass Transition of the LSE's ESI IDs pursuant to Section 15.1.2.9, Mass Transition. If an Emergency QSE that is a Resource Entity fails to meet at least one of the requirements listed above within the allotted time, ERCOT may allow the Resource Entity additional time, as determined by ERCOT staff, to meet the requirements.

16.2.7 Acceleration

Upon termination of a QSE's rights as a QSE and the Standard Form Market Participant Agreement or any other Agreement(s) between ERCOT and the QSE, all sums owed to ERCOT are immediately accelerated and are immediately due and owing in full. At that time, ERCOT may immediately draw upon any security or other collateral pledged to ERCOT and may offset or recoup all amounts due to ERCOT to satisfy those due and owing amounts.

16.3 Registration of Load Serving Entities

(1) LSEs provide electric service to Customers and Wholesale Customers. LSEs include Non-Opt In Entities (NOIEs) that serve Load and Competitive Retailers (CRs) (which includes Retail Electric Providers (REPs)). Each LSE operating in ERCOT, or in Non-

ERCOT portions of Texas in areas where Customer Choice is in effect, must register with ERCOT. To become registered as an LSE, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22) and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of an LSE under these Protocols. Additionally, a REP must demonstrate certification by P.U.C. SUBST. R. 25.107, Certification of Retail Electric Providers, and comply with the remaining requirements of this Section.

(2) All CRs must participate in and successfully complete testing as described in Section 23, Texas Test Plan Team - Retail Market Testing, prior to commencing operations with ERCOT.

(3) ERCOT may require that the Entity satisfactorily complete testing of interfaces between the Entity's systems and relevant ERCOT Systems.

16.3.1 Technical and Managerial Requirements for LSE Applicants

An LSE applicant must:

(1) Be capable of complying with all policies, rules, guidelines, registration requirements and procedures established by these Protocols, ERCOT, or other Independent Organizations, if applicable;

(2) Be capable of purchasing power from Entities registered with or by ERCOT or the Independent Organizations and capable of complying with its system rules; and,

(3) Be capable of purchasing capacity and reserves, or other Ancillary Services, as may be required by ERCOT, or other Independent Organizations, to provide adequate electricity to all the applicant's Customers.

16.3.1.1 Designation of a Qualified Scheduling Entity

(1) Each LSE applicant within the ERCOT Region shall designate in its application the QSE that will represent the applicant with ERCOT. Each applicant shall acknowledge in its application that it bears sole responsibility for selecting and maintaining a QSE as its representative. The applicant shall include in its application a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the applicant's transactions pursuant to these Protocols.

(2) An LSE may be required to designate a backup QSE under this Section.

(3) If an LSE fails to maintain a QSE as its representative, the LSE may be designated as an Emergency QSE as provided in this Section.

16.3.2 Registration Process for Load Serving Entities

(1) Any Entity providing electric service to Customers in ERCOT, or in Non-ERCOT portions of Texas in areas where Customer Choice is in effect, must submit to ERCOT a Load Serving Entity Application ("LSE application"). ERCOT shall post on the MIS Public Area the form in which LSE applications must be submitted, all materials that must be provided with the LSE application, and the fee schedule, if any, applicable to LSE applications.

(2) The LSE application must be attested to by a duly authorized officer or agent of the applicant. The applicant shall promptly notify ERCOT of any material changes affecting a pending LSE application using the appropriate form posted on the MIS Public Area.

16.3.2.1 Notice of Receipt of Load Serving Entity Application

Within three Business Days after receiving an LSE application, ERCOT shall issue the LSE applicant a written confirmation that ERCOT has received the LSE application. ERCOT shall return without review any LSE application that does not include the proper application fee. The remainder of this Section does not apply to any LSE application returned for failure to include the proper application fee.

16.3.2.2 Incomplete Load Serving Entity Applications

(1) Not more than ten Business Days after receiving an LSE application, ERCOT shall notify the applicant in writing whether the application is complete.

(2) If ERCOT determines that an LSE application is not complete, ERCOT's notice must explain the reasons for that determination and the additional information necessary to make the application complete. The applicant has five Business Days from receiving ERCOT's notice, or such longer period as ERCOT may allow, to provide the additional information set forth in ERCOT's notice. If the applicant timely responds to ERCOT's notice with the required additional information, then the application is deemed complete on the date that ERCOT receives the applicant's response.

(3) If the applicant does not timely respond to ERCOT's Notice, then the application must be rejected, and ERCOT shall retain any application fee included with the application.

16.3.2.3 ERCOT Approval or Rejection of Load Serving Entity Application

(1) ERCOT may reject an LSE application within ten Business Days after the application has been deemed complete in accordance with this Section. If ERCOT does not reject the LSE application within ten Business Days after the application is deemed complete then the application is deemed approved.

(2) If ERCOT rejects a LSE application, ERCOT shall send the LSE applicant a rejection letter explaining the grounds upon which ERCOT rejected the LSE application. Appropriate grounds for rejecting a LSE application include the following:

(a) Required information is not provided to ERCOT in the allotted time;

(b) Noncompliance with technical requirements; and

(c) Noncompliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the LSE applicant may challenge the rejection of its LSE application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new LSE application and fee at any time, and ERCOT shall process the new LSE application under this Section.

16.3.3 Changing QSE Designation

(1) An LSE may change its designation of QSE no more than once in any consecutive three days.

(2) The LSE shall include a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the LSE's transactions under these Protocols.

(3) If an LSE's representation by a QSE will terminate or the LSE intends to be represented by a different QSE, the LSE shall submit updated QSE designation information to ERCOT no less than six days prior to the effective date. Within two days of receiving that notice, ERCOT shall notify all affected Entities, including the LSE's current QSE, of the effective date of the change.

16.3.4 Maintaining and Updating LSE Information

Each LSE must timely update information the LSE provided to ERCOT in the application process, and an LSE must promptly respond to any reasonable request by ERCOT for updated information regarding the LSE or the information provided to ERCOT by the LSE, including:

(a) The LSE's addresses;

(b) A list of Affiliates; and

(c) Designation of the LSE's officers, directors, Authorized Representatives, and User Security Administrator (all per the LSE application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

16.3.5 Load Serving Entities Outside of ERCOT

(1) LSEs operating only outside of the ERCOT Region are not required to designate a QSE.

(2) Each LSE operating only outside of the ERCOT Region but within Texas ("Non-ERCOT LSE") is required to register with ERCOT but is not required to comply with those sections of the Protocols that relate only to operations in the ERCOT Region.

16.4 Registration of ERCOT and Non-ERCOT Transmission and Distribution Service Providers

(1) Each Entity operating as a Transmission Service Provider (TSP) or Distribution Service Provider (DSP) within the ERCOT Region, including Municipally Owned Utilities and Electric Cooperatives, shall register as a TSP or DSP, or both, as applicable, with ERCOT. Any DSP operating only outside of the ERCOT Region, but within Texas ("Non-ERCOT DSP") shall also register as a DSP, but Non-ERCOT DSPs are not required to comply with sections of the Protocols relating only to operations in the ERCOT Region. To register as a TSP or DSP, an Entity must comply with the backup plan requirements in the Operating Guides, execute a Standard Form Market Participant Agreement (using the form provided in Section 22), and be capable of performing the functions of a TSP or DSP, as applicable, as described in these Protocols.

(2) DSPs operating within portions of Texas in areas where Customer Choice is in effect (including Opt-In MOUs and Opt-In Co-ops) must participate in and successfully complete testing as described in Section 23, Texas Test Plan Team - Retail Market Testing, before starting operations with ERCOT.

16.5 Registration of a Resource Entity

A Resource Entity owns or controls an All-Inclusive Resource connected to the ERCOT System. Each Resource Entity operating in ERCOT must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22) and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall register each All-Inclusive Resource with ERCOT through ERCOT registration.

16.5.1 Technical and Managerial Requirements for Resource Entity Applicants

A Resource Entity applicant must:

(1) Be capable of complying with all policies, rules, guidelines, registration requirements, and procedures established by these Protocols, ERCOT, or other Independent Organizations, if applicable; and

(2) Be capable of purchasing power from Entities registered with or by ERCOT or the Independent Organizations and capable of complying with its system rules.

16.5.1.1 Designation of a Qualified Scheduling Entity

(1) Each Resource Entity applicant within the ERCOT Region shall designate in its application the Qualified Scheduling Entity (QSE) that will represent the applicant with ERCOT. Each applicant shall acknowledge in its application that it bears sole responsibility for selecting and maintaining a QSE as its representative. The applicant shall include in its application a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the applicant's transactions pursuant to these Protocols.

(2) A Resource Entity may be required to designate a backup QSE under this Section.

16.5.1.2 Waiver for Federal Hydroelectric Facilities

(1) ERCOT may grant a waiver to any federally owned hydroelectric All-Inclusive Resource within the ERCOT System from fulfilling the requirements in Section 16.5, Registration of a Resource Entity, as they pertain to the submission of a Resource Entity application and the execution of a Resource Entity Agreement (Section 22 Attachment E, Standard Form Resource Entity Agreement). ERCOT may grant such waiver after the federally owned hydroelectric Resource Entity provides ERCOT with the following:

(a) All information necessary to meet the Resource Entity registration requirements as provided in this Section;

(b) The designation of a QSE for each All-Inclusive Resource that it owns or controls; and

(c) Assignment of each All-Inclusive Resource's Electric Service Identifier (ESI ID) to a Load Serving Entity (LSE) serving any Load or net Load, if the All-Inclusive Resource is net metered and will be connected to the ERCOT System. Such Load, if retail Load, is subject to all applicable rules and procedures, including rules concerning disconnection and Provider of Last Resort (POLR) service, applicable to other retail points of delivery.

16.5.1.3 Waiver for Block Load Transfer Resources

ERCOT may grant a waiver to a Resource Entity for a Block Load Transfer (BLT) Resource from fulfilling the requirements in Section 16.5, Registration of a Resource Entity, as they pertain to the submission of a Resource Entity application and the execution of a Resource Entity Agreement (Section 22 Attachment E, Standard Form Resource Entity Agreement). ERCOT may grant such waiver after the Resource Entity for the BLT Resource provides ERCOT with the following:

(a) All applicable information necessary to meet the Resource Entity registration requirements as provided in this Section; and,

(b) The designation of a QSE for the BLT Resource.

16.5.2 Registration Process for a Resource Entity

(1) To register as a Resource Entity, an applicant must submit to ERCOT a completed Resource Entity application and any applicable fee. ERCOT shall post on the Market Information System (MIS) Public Area the form in which Resource Entity applications must be submitted, all materials that must be provided with the Resource Entity application.

(2) The Resource Entity application must be attested to by a duly authorized officer or agent of the applicant. The applicant shall promptly notify ERCOT of any material changes affecting a pending Resource Entity application using the appropriate form posted on the MIS Public Area.

16.5.2.1 Notice of Receipt of Resource Entity Application

Within three Business Days after receiving a Resource Entity application, ERCOT shall issue the Resource Entity applicant a written confirmation that ERCOT has received the application. ERCOT shall return without review any Resource Entity application that is not complete.

16.5.2.2 Incomplete Resource Entity Applications

(1) Not more than ten Business Days after receiving a Resource Entity application, ERCOT shall notify the applicant in writing whether the application is complete.

(2) If ERCOT determines that a Resource Entity application is not complete, ERCOT's notice must explain the reasons for that determination and the additional information necessary to make the application complete. The applicant has five Business Days from receiving ERCOT's notice, or such longer period as ERCOT may allow, to provide the additional information set forth in ERCOT's notice. If the applicant timely responds to ERCOT's notice with the required additional information, then the application is deemed complete on the date that ERCOT receives the applicant's response.

(3) If the applicant does not timely respond to ERCOT's notice, then the application must be rejected, and ERCOT shall retain any application fee included with the application.

16.5.2.3 ERCOT Approval or Rejection of a Resource Entity Application

(1) ERCOT may reject a Resource Entity application within ten Business Days after the application has been deemed complete in accordance with this Section. If ERCOT does

not reject the Resource Entity application within ten Business Days after the application is deemed complete then the application is deemed approved.

(2) If ERCOT rejects a Resource Entity application, ERCOT shall send the Resource Entity applicant a rejection letter explaining the grounds upon which ERCOT rejected the Resource Entity application. Appropriate grounds for rejecting a Resource Entity application include the following:

(a) Required information is not provided to ERCOT in the allotted time;

(b) Noncompliance with technical requirements; and

(c) Noncompliance with other specific eligibility requirements set forth in this Section or in any other part of these Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the Resource Entity applicant may challenge the rejection of its Resource Entity application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new Resource Entity application and fee at any time, and ERCOT shall process the new Resource Entity application under this Section.

16.5.3 Changing QSE Designation

(1) A Resource Entity may change its designation of QSE no more than once in any consecutive three days.

(2) The Resource Entity shall include a written statement from the designated QSE acknowledging that the QSE accepts responsibility for the Resource Entity's transactions under these Protocols.

(3) If a Resource Entity's representation by a QSE will terminate or the Resource Entity intends to be represented by a different QSE, the Resource Entity shall submit updated QSE designation information to ERCOT no less than six days prior to the effective date. Within two days of receiving that notice, ERCOT shall notify all affected Entities, including the Resource Entity's current QSE, of the effective date of the change.

16.5.4 Maintaining and Updating Resource Entity Information

(1) Each Resource Entity must timely update information the Resource Entity provided to ERCOT in the application process, and a Resource Entity must promptly respond to any reasonable request by ERCOT for updated information regarding the Resource Entity or the information provided to ERCOT by the Resource Entity, including:

(a) The Resource Entity's addresses;

(b) A list of Affiliates; and

(c) Designation of the Resource Entity's officers, directors, Authorized Representatives, and User Security Administrator (all per the Resource Entity application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

(2) If a Resource Entity has a Switchable Generation Resource with a requirement in a non-ERCOT Control Area for the months of July through August ("Peak Period"), it shall report to ERCOT in writing, annually by April 1, the days that the identified capacity will not be available to the ERCOT System during the Peak Period.

16.6 Registration of Municipally Owned Utilities and Electric Cooperatives in the ERCOT Region

(1) Each Municipally Owned Utility (MOU) and Electric Cooperative (EC) shall register with ERCOT and sign the Agreements that apply to the functions it performs in the ERCOT Region, regardless of whether planning to be a Non-Opt-In Entity (NOIE) or a Competitive Retailer.

(2) Each MOU and EC that decides to opt in shall register as a Competitive Retailer and notify ERCOT of its intentions six months prior to opting in.

(3) Each MOU and EC shall designate a QSE with ERCOT on its behalf.

(4) ERCOT shall create and assign each NOIE an ESI ID to each NOIE wholesale point of delivery as specified in these Protocols. The ESI IDs must be assigned to an LSE.

16.7 Registration of Renewable Energy Credit Account Holders

Each Entity intending to participate in the REC Program shall register with ERCOT and execute a REC Account Holder Agreement (as provided in Section 22, Agreements) prior to participation in the REC Program.

16.8 Registration and Qualification of Congestion Revenue Rights Account Holders

16.8.1 Criteria for Qualification as a CRR Account Holder

(1) To become and remain a CRR Account Holder, an Entity must meet the following requirements:

(a) Submit a properly completed CRR Account Holder application for qualification, including any applicable fee and including designation of "Authorized Representatives," each of whom is responsible for administrative communications with the CRR Account Holder and each of whom has enough authority to commit and bind the CRR Account Holder;

(b) Sign a CRR Account Holder Agreement;

(c) Sign any required Agreements relating to use of the ERCOT network, software, and systems;

(d) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of performing the functions of a CRR Account Holder;

(e) Demonstrate to ERCOT's reasonable satisfaction that the Entity is capable of complying with the requirements of all ERCOT Protocols and Operating Guides;

(f) Satisfy ERCOT's creditworthiness requirements as set forth in this Section;

(g) Be generally able to pay its debts as they come due; ERCOT may request evidence of compliance with this qualification only if ERCOT reasonably believes that a CRR Account Holder is failing to comply with it;

(h) Provide all necessary bank account information and arrange for Fedwire system transfers for two-way confirmation;

(i) Be financially responsible for payment of its settlement charges under these Protocols; and

(j) Not be an unbundled TSP, DSP, or an ERCOT employee.

(2) A CRR Account Holder shall promptly notify ERCOT of any change that materially affects the Entity's ability to satisfy the criteria set forth above, and of any material change in the information provided by the CRR Account Holder to ERCOT that may adversely affect the financial security of ERCOT. If the CRR Account Holder fails to so notify ERCOT within one day after the change, then ERCOT may refuse to allow the CRR Account Holder to perform as a CRR Account Holder and may take any other action ERCOT deems appropriate, in its sole discretion, to prevent ERCOT or Market Participants from bearing potential or actual risks, financial or otherwise, arising from those changes, and in accordance with these Protocols.

(3) Continued qualification as a CRR Account Holder is contingent upon compliance with all applicable requirements in these Protocols. ERCOT may suspend a CRR Account Holder's rights as a Market Participant when ERCOT reasonably determines that it is an appropriate remedy for the Entity's failure to satisfy any applicable requirement.

16.8.2 CRR Account Holder Application Process

To register as a CRR Account Holder, an applicant must submit to ERCOT a completed CRR Account Holder application and any applicable fee. ERCOT shall post on the MIS Public Area the form in which CRR Account Holder applications must be submitted, all materials that must be provided with the CRR Account Holder application and the fee schedule, if any, applicable to CRR Account Holder applications. The CRR Account Holder application shall be attested to by a duly authorized officer or agent of the applicant. The CRR Account Holder applicant shall promptly notify ERCOT of any material changes affecting a pending application using the appropriate form posted on the MIS Public Area. The application must be submitted at least 15 days before the first day of participation in the CRR Auction process or purchase of CRRs.

16.8.2.1 Notice of Receipt of CRR Account Holder Application

Within three Business Days after receiving a CRR Account Holder application, ERCOT shall issue to the applicant a written confirmation that ERCOT has received the CRR Account Holder application. ERCOT shall return without review any CRR Account Holder application that does not include the proper application fee. The remainder of this Section does not apply to any CRR Account Holder application returned for failure to include the proper application fee.

16.8.2.2 Incomplete Applications

(1) Within ten Business Days after receiving a CRR Account Holder application, ERCOT shall notify the applicant in writing if the application is incomplete. If ERCOT fails to notify the applicant that the application is incomplete within ten Business Days, then the application is considered complete as of the date ERCOT received it.

(2) If a CRR Account Holder application is incomplete, ERCOT's notice of incompletion to the applicant must explain the deficiencies and describe the additional information necessary to make the CRR Account Holder application complete. The CRR Account Holder applicant has five Business Days after it receives the notice, or a longer period if ERCOT allows, to provide the additional required information. If the applicant responds to the notice within the allotted time, then the CRR Account Holder application is considered complete on the date that ERCOT received the complete additional information from the applicant.

(3) If the applicant does not respond to the incompletion notice within the time allotted, ERCOT shall reject the application and shall notify the applicant using the procedures below.

16.8.2.3 ERCOT Approval or Rejection of CRR Account Holder Application

(1) ERCOT may reject a CRR Account Holder application within ten Business Days after the application has been deemed complete in accordance with this Section. If ERCOT does not reject the CRR Account Holder application within ten Business days after the application is deemed complete then the application is deemed approved.

(2) If ERCOT rejects a CRR Account Holder application, ERCOT shall send the applicant a rejection letter explaining the grounds upon which ERCOT rejected the CRR Account Holder application. Appropriate grounds for rejecting a CRR Account Holder application include the following:

    (a) Required information is not provided to ERCOT in the allotted time;

(b) Noncompliance with technical requirements; and

(c) Noncompliance with other specific eligibility requirements in this Section or in any other Protocols.

(3) Not later than ten Business Days after receiving a rejection letter, the CRR Account Holder applicant may challenge the rejection of its CRR Account Holder application using the dispute resolution procedures set forth in Section 20, Alternative Dispute Resolution Procedure. The applicant may submit a new CRR Account Holder application and fee at any time, and ERCOT shall process the new CRR Account Holder application under this Section.

(4) If ERCOT does not reject the CRR Account Holder application within ten Business Days after the application has been deemed complete under this Section, ERCOT shall send the applicant, a CRR Account Holder Agreement and any other required agreements relating to use of the ERCOT network, software, and systems for the applicant's signature.

16.8.3 Remaining Steps for CRR Account Holder Registration

After a CRR Account Holder application is deemed approved under Section 16.8.2.3, ERCOT Approval or Rejection of CRR Account Holder Application, the applicant shall coordinate or perform the following:

(a) Return the signed CRR Account Holder Agreement and other related agreements to ERCOT; and

(b) Demonstrate compliance with security and financial requirements.

16.8.3.1 Maintaining and Updating CRR Account Holder Information

Each CRR Account Holder must timely update information the CRR Account Holder provided to ERCOT in the application process, and a CRR Account Holder must promptly respond to any reasonable request by ERCOT for updated information regarding the CRR Account Holder or the information provided to ERCOT by the CRR Account Holder, including:

(a) The CRR Account Holder's addresses;

(b) A list of Affiliates; and

(c) Designation of the CRR Account Holder's officers, directors, Authorized Representatives, Credit Contacts, and User Security Administrator (all per the CRR Account Holder application) including the addresses (if different), telephone and facsimile numbers, and e-mail addresses for those persons.

16.9 Resources Providing Reliability Must-Run Service

Any Entity providing Reliability Must-Run (RMR) Service must comply with all the requirements to become a Resource Entity under this Section and must sign an RMR Agreement (Section 22, Attachment B, Standard Form Reliability Must-Run Agreement).

16.10 Resources Providing Black Start Service

Any Entity providing Black Start Service must comply with all the requirements to become a Resource Entity under this Section and must sign a Black Start Agreement (Section 22, Attachment A, Standard Form Black Start Agreement).

16.11 Financial Security for Counter-Parties

The term "Financial Security" in this Section means the collateral amount posted with ERCOT in any of the forms listed in Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

16.11.1 ERCOT Creditworthiness Requirements for Counter-Parties

Each Counter-Party shall meet ERCOT's creditworthiness standards as provided in this Section. A Counter-Party must, at all times, maintain its Financial Security at or above the amount of its Total Potential Exposure (TPE) minus its Unsecured Credit Limit. Each Counter-Party shall maintain any required Financial Security in a form acceptable to ERCOT in its sole discretion. If at any time the Counter-Party does not meet ERCOT's creditworthiness requirements, then ERCOT may suspend the Counter-Party's rights under these Protocols until it meets those creditworthiness requirements. ERCOT's failure to suspend the Counter-Party's rights on any particular occasion does not prevent ERCOT from suspending those rights on any subsequent occasion, including a CRR Account Holder's ability to bid on future CRRs or a QSE's ability to bid in the Day-Ahead Market.

16.11.2 Requirements for Setting a Counter-Party's Unsecured Credit Limit

(1) The terms Minimum Credit Rating, Credit Rating, Minimum Equity, Minimum Average Times/Interest Earning Ratio (TIER) and Debt Service Coverage (DSC) Ratios, Maximum Debt to Total Capitalization Ratio, Minimum Equity to Assets Ratio, Minimum Earnings Before Interest, Taxes, Depreciation, Amortization (EBITDA) to Interest and Current Maturities of Long-Term Debt (CMLTD) ratio, Unsecured Credit Limit and Minimum Equity Ratios are defined in the ERCOT Creditworthiness Standards adopted by the ERCOT Board of Directors and published on the MIS Public Area.

(2) ERCOT, in its sole discretion, may set an Unsecured Credit Limit for a Counter-Party if it meets one of the following requirements:

(a) Has at least the required Minimum Equity and a Credit Rating that meets or exceeds the Minimum Credit Rating; or

(b) Is an Electric Cooperative without a Credit Rating, and:

(i) Is a Rural Utilities Service (RUS) distribution borrower or power supply borrower as those terms are used in Chapter 7 of the Code of Federal Regulations, (7 C.F.R.) § 1717.656 (2005);

(ii) Maintains at least the required minimum average TIER and DSC ratios, as defined in 7 C.F.R § 1710.114 (2005)

(iii) Maintains at least the required Minimum Equity to Assets Ratio; and

(iv) Maintains at least the required Minimum Equity; or

(c) Is a Municipal Entity without a Credit Rating, and

(i) Maintains at least the required minimum average TIER and DSC ratios;

(ii) Maintains at least the required Minimum Equity to Assets Ratio; and

(iii) Maintains at least the required Minimum Equity; or

(d) Is a privately held company without a Credit Rating, and

(i) Has equity in the amount equal to or greater than the required Minimum Equity;

(ii) Maintains at most the Maximum Debt to Total Capitalization Ratio; and

(iii) Maintains at least the required Minimum Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) to Interest and Current Maturities of Long-Term Debt (CMLTD) ratio.

16.11.3 Alternative Means of Satisfying ERCOT Creditworthiness Requirements

If a Counter-Party is required to provide Financial Security under these Protocols, then it may do so through one or more of the following means:

(a) Another Entity may give a guarantee to ERCOT, if ERCOT has set an Unsecured Credit Limit for the Entity under the standards in Section 16.11.2, Requirements for Setting a Counter-Party's Unsecured Credit Limit, paragraph (2). ERCOT shall value the guarantee based on the guarantor's Unsecured Credit Limit and other obligations the guarantor has under these Protocols or other contracts with ERCOT. The guarantee must be given using one of the ERCOT Board-approved standard guarantee forms.

(b) The Counter-Party may give an unconditional, irrevocable letter of credit naming ERCOT as the beneficiary. ERCOT may, in its sole discretion, reject the letter of credit if the issuer is unacceptable to ERCOT or if the conditions under which ERCOT may draw against the letter of credit are unacceptable to ERCOT. The letter of credit must be given using the ERCOT Board-approved standard letter of credit form.

(c) The Counter-Party may give a surety bond naming ERCOT as the beneficiary. The surety bond must be signed by a surety acceptable to ERCOT, in its sole discretion, in compliance with limits set by the ERCOT Creditworthiness Standards, and must be in the form of ERCOT's standard surety bond form.

(d) The Counter-Party may deposit cash in an account designated by ERCOT with the understanding that ERCOT may draw part or all of the deposited cash to satisfy any overdue payments owed by the Counter-Party to ERCOT. The account may bear interest payable directly to the Counter-Party, but any such arrangements may not restrict ERCOT's immediate access to the cash. ERCOT has a security interest in all property delivered by the Counter-Party to ERCOT from time to time to meet the creditworthiness requirements, and that property secures all amounts owed by the Counter-Party to ERCOT.

16.11.4 Determination and Monitoring of Counter-Party Credit Exposure

16.11.4.1 Determination of Total Potential Exposure for a Counter-Party

(1) A Counter-Party's "Total Potential Exposure" (TPE) is, (i) for a Counter-Party that has granted ERCOT a first priority security interest in receivables generated under or in connection with the Counter-Party Agreement or is an Electric Cooperative or an Entity created under Texas Water Code (TWC) § 222.001, Creation,, the algebraic sum of its current and future credit exposures, and (ii) for every other Counter-Party, the sum of its current credit exposure, if positive, and future credit exposures, if positive.

(a) Current credit exposure is calculated as the Initial Estimated Liability (IEL) or the greater of its Estimated Aggregate Liability (EAL), Aggregate Incremental Liability (AIL) or the sum of its EAL and AIL. Current credit exposure includes the following:

(i) Obligations as a result of the Adjustment Period operations and Real-Time operations, including emergency operations;

(ii) Known obligations in the Day-Ahead Market; and

(iii) CRR-related known obligations.

(b) Future Credit Exposure is calculated as the FCE that reflects the future mark to market value of CRRs registered in the name of the Counter-Party.

(2) For a Counter-Party that has granted ERCOT a first priority security interest in receivables generated under or in connection with the Counter-Party Agreement or is an Electric Cooperative or an Entity created under TWC §222.001:

TPE = Max [(IEL for the first 60 days), EAL, AIL, (EAL+AIL)] + FCE

For all other Counter-Parties:

TPE = Max [0, (IEL for the first 60 days), EAL, AIL, (EAL+AIL)] + Max [0, FCE]

(3) If ERCOT, in its sole discretion, determines that the TPE for a Counter-Party calculated under paragraph (1) above does not adequately match the financial risk created by that Counter-Party's activities under these Protocols, then ERCOT may set a different TPE for that Counter-Party. ERCOT shall, to the extent practical, give to the Counter-Party the information used to determine that different TPE. ERCOT shall provide written or electronic notice to the Counter-Party of the basis for ERCOT's assessment of the Counter-Party's financial risk and the resulting creditworthiness requirements.

16.11.4.2 Determination of Counter-Party Initial Estimated Liability

(1) For each Counter-Party, ERCOT shall determine an Initial Estimated Liability (IEL) for purposes of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements, until ERCOT issues the first Invoice for the Counter-Party. After ERCOT issues the first Invoice, it shall calculate credit exposure based on the Counter-Party's Estimated Aggregate Liability (EAL).

(2) For a Counter-Party that is a QSE representing only Load-Serving Entities (LSEs), ERCOT shall calculate the IEL using the following formula:

IEL = DEL × Max [0.2, RTEFL] × RTAEP × 40

The above variables are defined as follows:

Variable	**Unit**	**Description**
IEL	$	*Initial Estimated Liability*—The Counter-Party's Initial Estimated Liability.
DEL	MWh	*Daily Estimated Load*—The Counter-Party's estimated average daily Load as determined by ERCOT based on information provided by the Counter-Party.
RTEFL	none	*Real-Time Energy Factor for Load* - The ratio of the Counter-Party's estimated energy purchases in the Real-Time market as determined by ERCOT based on information provided by the Counter-Party, to the Counter-Party's Daily Estimated Load.
RTAEP	$/MWh	*Real-Time Average Energy Price*—Average Settlement Point Price for the "ERCOT 345" as defined in Section 3.5.2.5, ERCOT Hub Average 345 kV Trading Hub (ERCOT 345), based upon the previous seven days' average Real-Time Settlement Point Prices.

(3) For a Counter-Party that is a QSE representing only Resources, ERCOT shall calculate the IEL using the following formula:

$$\textbf{IEL} = \textbf{DEG} \times \textbf{Max [0.2, RTEFG]} \times \textbf{RTAEP} \times \textbf{40}$$

The above variables are defined as follows:

Variable	Unit	Description
IEL	$	*Initial Estimated Liability*—The Counter-Party's Initial Estimated Liability.
DEG	MWh	*Daily Estimated Generation*—The Counter-Party's estimated average daily generation as determined by ERCOT based on information provided by the Counter-Party.
RTEFG	none	*Real-Time Energy Factor for Generation*— The ratio of the Counter-Party's estimated energy sales in the Real-Time market as determined by ERCOT based on information provided by the Counter-Party, to the Counter-Party's Daily Estimated Generation.
RTAEP	$/MWh	*Real-Time Average Energy Price*—Average Settlement Point Price for the "ERCOT 345" as defined in Section 3.5.2.5, ERCOT Hub Average 345 kV Trading Hub (ERCOT 345), based upon the previous seven days average Real-Time Settlement Point Prices.

(4) For a Counter-Party that is a QSE representing both LSE and Resources, ERCOT shall calculate the Counter-Party's IEL using the following formula:

$$\textbf{IEL} = \textbf{DEL} \times \textbf{Max [0.1, RTEFL]} \times \textbf{RTAEP} \times \textbf{40} + \textbf{DEG} \times \textbf{Max [0.1, RTEFG]} \times \textbf{RTAEP} \times \textbf{40}$$

The above variables are defined as follows:

Variable	Unit	Description
IEL	$	*Initial Estimated Liability*—The Counter-Party's Initial Estimated Liability.
DEL	MWh	*Daily Estimated Load*— The Counter-Party's estimated average daily Load as determined by ERCOT based on information provided by the Counter-Party.
DEG	MWh	*Daily Estimated Generation*— The Counter-Party's estimated average daily generation as determined by ERCOT based on information provided by the Counter-Party.
RTEFL	none	*Real-Time Energy Factor for Load*— The ratio of the Counter-Party's estimated energy purchases in the Real-Time market as determined by ERCOT based on information provided by the Counter-Party, to the Counter-Party's Daily Estimated Load.
RTAEP	$/MWh	*Real-Time Average Energy Price*— Average Settlement Point Price for the "ERCOT 345" as defined in Section 3.5.2.5, ERCOT Hub Average 345 kV Trading Hub (ERCOT 345), based upon the previous seven days' average Real-Time Settlement Point Prices.

RTEFG	none	*Real-Time Energy Factor for Generation*— The ratio of the Counter-Party's estimated energy sales in the Real-Time market as determined by ERCOT, based on information provided by the Counter-Party, to the Counter-Party's Daily Estimated Generation.

(5) For a Counter-Party that is only a CRR Account Holder and is not a QSE, the IEL is zero.

16.11.4.3 Determination of Counter-Party Estimated Aggregate Liability

After a Counter-Party receives its first Invoice, ERCOT shall monitor and calculate the Counter Party's Estimated Aggregate Liability (EAL) on Business Days based on the formula below.

EAL = Max [IEL during the first 60-day period, Max (ADTE during the previous 60-day period)] + OUT + PUL + DALE

The above variables are defined as follows:

Variable	Unit	Description
EAL	$	*Estimated Aggregate Liability*—Estimated Aggregate Liability for the Counter-Party.
IEL	$	*Initial Estimated Liability*—Initial Estimated Liability (as defined in Section 16.11.4.2, Determination of Counter-Party Initial Estimated Liability) for the Counter-Party.
ADTE	$	*Average Daily Transaction Extrapolated*—Forty days multiplied by the sum of the net amount due from or to ERCOT by the Counter-Party in Initial Settlement Statements included in the Counter-Party's two most recent Real-Time Settlement Invoices divided by the number of Initial Settlement Statements included in those two Settlement Invoices. (The Real-Time Initial Settlement Invoices includes settlement of Real-Time CRRs.)
OUT	$	*Outstanding Unpaid Transactions*—Outstanding, unpaid transactions of the Counter-Party, which include (1) outstanding Invoices to the Counter-Party, including Invoices for DAM activity and CRR Auction activity and (2) estimated unbilled items to the Counter-Party, to the extent not adequately accommodated in the ADTE calculation (including resettlements and other known liabilities). The Counter-Party's Invoices for Real-Time transactions may not be considered outstanding for purposes of this calculation if paid on or before the second Business Day after the Invoice is issued.
PUL	$	*Potential Uplift*—Potential uplift to the Counter-Party, to the extent and in the proportion that the Counter-Party represents Entities to which an uplift of a short payment will be made pursuant to Section 9.7.3, Partial Payments by Invoice Recipients for the RTM. It is calculated as the sum of: (a) Amounts expected to be uplifted within one year of the date of the calculation; and (b) Twenty-five percent, or such other percentage based on available statistics regarding payment default under bankruptcy reorganization plans, of any short payment amounts being repaid to ERCOT under a bankruptcy reorganization plan that are due more than one year from the date of the calculation.

Variable	Unit	Description
DALE	$	*Average Daily DA Liability Extrapolated*—Sixteen days multiplied by the sum of the net amount due to or from ERCOT in DAM Settlement Statements (that includes Ancillary Services and CRRs cleared and bought in the DAM) included in the seven most recent DAM Settlement Invoices divided by the number of DAM Settlement Statements included in those seven DAM Settlement Invoices.

16.11.4.4 Determination of Counter-Party Aggregate Incremental Liability

ERCOT shall monitor and calculate an Aggregate Incremental Liability (AIL) on Business Days for each Counter-Party using the formula below:

$$\mathbf{AIL} = \sum_{d} (\mathbf{RTL_d}) - \mathbf{Max[0, (ADTE / 40 \times N \times 0.9)]}$$

The above variables are defined as follows:

Variable	Unit	Description
AIL	$	*Aggregate Incremental Liability*—The amount by which the calculated incremental liability of the Counter-Party for all relevant days, N, exceeds the ADTE.
RTL	$	*Real-Time Liability*—The estimated or settled amounts due from or to ERCOT due to activities in the Real Time and Adjustment Period. Real-Time Liability is the amounts for Load increased by amounts for awarded DAM Energy Offers, and Energy Trade sales and is decreased by amounts for awarded DAM Energy Bids, Energy Trade purchases, and estimated or settled amounts for generation. In addition Real-Time Liability will be adjusted for CRRs settled in Real Time and for other amounts due to or from ERCOT by the Counter-Party. Real-Time Liability is determined over all Settlement Points and all Settlement Intervals over all relevant days, as follows: (a) For each Operating Day that is completed and settled but for which no Invoice has been issued, ERCOT shall calculate RTL using Settlement Statement data; (b) For each Operating Day that is completed but not settled or for which no Invoice has been issued, ERCOT shall calculate RTL as the higher of ERCOT's estimate of the Counter-Party's RTL for the day or the Counter-Party's estimate of RTL for the day; and (c) For seven Operating Days that are not yet completed, ERCOT shall calculate RTL as the higher of 150% of ERCOT's estimate of the Counter-Party's RTL for the most recent seven days or the Counter-Party's forecast of RTL for the next seven days.
ADTE	$	*Average Daily Transaction Extrapolated*— Forty days multiplied by the sum of the net amount due from or to ERCOT by the Counter-Party in Initial Settlement Statements included in the Counter-Party's two most recent Real-Time Settlement Invoices divided by the number of Initial Settlement Statements included in those two Settlement Invoices.
d	none	One Operating Day in the period of relevant days.
N	none	All relevant days, i.e., the number of Operating Days that have not been invoiced plus seven future days.

16.11.4.5 Determination of the Counter-Party Future Credit Exposure

(1) ERCOT shall monitor and calculate the Counter-Party's Future Credit Exposure (FCE) on Business Days for all CRRs held by the Counter-Party as owner of record at ERCOT, for all Operating Days that have not yet occurred and for CRRs that have not settled, using the formula below.

$$\mathbf{FCE_o = FCEOBL_o + FCEOPT_o + FCRFGR_o}$$

The above variables are defined as follows:

Variable	Unit	Description
FCE_o	$	*Future Credit Exposure* - Counter-Party Future Credit Exposure for all CRRs held by the Counter-Party as owner *o* of record at ERCOT, for all Operating Days that have not yet occurred and for CRRs that have not settled.
$FCEOBL_o$	$	*Future Credit Exposure for PTP Obligations* - Counter-Party Future Credit Exposure for all PTP Obligations held by the Counter-Party as owner *o* of record at ERCOT, for all Operating Days that have not yet occurred and for CRRs that have not settled.
$FCEOPT_o$	$	*Future Credit Exposure for PTP Options* - Counter-Party Future Credit Exposure for all PTP Options held by the Counter-Party as owner *o* of record at ERCOT, for all Operating Days that have not yet occurred and for CRRs that have not settled.
$FCEFGR_o$	$	*Future Credit Exposure for FGRs* - Counter-Party Future Credit Exposure for all FGRs held by the Counter-Party as owner *o* of record at ERCOT, for all Operating Days that have not yet occurred and for CRRs that have not settled.
o	none	A CRR Owner

(2) The Counter-Party's Future Credit Exposure for all PTP Obligations (FCEOBL) held by the Counter-Party as owner of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled is calculated as follows.

$$\mathbf{FCEOBL_o = Max\ (ACPEOBL_o, - FMMOBL_o)}$$

Where:

$$ACPEOBL_o = \sum_{(h)} \sum_{(j,k)} (ACPE_{h,\,(j,k)} * OBLMW_{o,\,h,\,(j,k)})$$

$$FMMOBL_o = \sum_{(h)} \sum_{(j,k)} [(W_1 * ACP_{h,\,(j,k)} + W_2 * TOBLV_{h,\,(j,k)} + W_3 * FDOBLV_{h,\,(j,k)} + W_4 * PMOBLV_{h,\,(j,k)}) * OBLMW_{o,\,h,\,(j,k)}]$$

If $FCEOBL_o$ is negative (a net asset to the Counter-Party), then the $FCEOBL_o$ will be recalculated using PTP Obligations registered in the name of the Counter-Party only for (a) the remaining hours of the current month and (b) all hours in the following month;

The above variables are defined as follows:

Variable	**Unit**	**Description**
$FCEOBL_o$	$	*Future Credit Exposure for PTP Obligations* - Counter-Party Future Credit Exposure for all PTP Obligations held by the Counter-Party as owner *o* of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled.
$ACPEOBL_o$	$	*Auction Clearing Price Exposure* for all PTP Obligations held by the Counter-party as owner *o* of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled.
$ACPE_{h, (j,k)}$	$/MW per hour	*Auction Clearing Price Exposure for PTP Obligations with the source j and the sink k for hour h* - Exposure level calculated as follows: • if the PTP Obligation Auction Clearing Price is greater than $15 per MW, then 150 divided by the PTP Obligation Auction Clearing Price; • if the PTP Obligation Auction Clearing Price is between $0 and $15 per MW, then $10 per MW; and • if the PTP Obligation Auction Clearing Price is negative, then $10 per MW, plus the absolute value of the PTP Obligation Auction Price per MW.
$FMMOBL_o$	$	*Forward Mark-to-Market for PTP Obligations* – Estimate of the forward mark-to-market value of PTP Obligations held by the Counter-Party as owner *o* of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled.
$ACP_{h, (j,k)}$	$/MW per hour	*Auction Clearing Price* - The auction clearing price of the PTP Obligation with the source *j* and the sink *k* for hour *h*.
$W_1 – W_4$	none	*Weighting*—The weighting associated with the pricing components that sum to 1. The values of these factors must be determined by the Credit Working Group and posted on the MIS Public Area. The weighting factors may be customizable for the month to which a CRR applies.
$TOBLV_{h, (j,k)}$	$/MW per hour	*Today's PTP Obligation Value* – The difference in current day's most recent DAM Settlement Point Price between the sink *k* and the source *j* of the CRR for the hour *h* owned. If the DAM is executed but specific DAM Settlement Point Price s are not available, ERCOT may use the appropriate Hub prices instead. If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$FDOBLV_{h, (j,k)}$	$/MW per hour	*Five-day PTP Obligation Value* – Average of the most recent rolling five-day difference in DAM Settlement Point Price between the sink *k* and the source *j* of the CRR for the hour *h* owned. If the DAM is executed but specific DAM Settlement Point Prices are not available, ERCOT may use the appropriate Hub prices instead. If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$PMOBLV_{h, (j,k)}$	$/MW per hour	*Previous Month's PTP Obligation Value* – Average of the previous month's daily difference in DAM Settlement Point Price between the sink *k* and the source *j* of the CRR for the hour *h* owned. If the DAM is executed but specific DAM Settlement Point Prices are not available, ERCOT may use the appropriate Hub prices instead. If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$OBLMW_{o, h, (j,k)}$	MW	*PTP Obligation* with the source *j* and the sink *k* for hour *h* owned by the Counter-Party as owner *o* for all Operating Days that have not yet occurred and for CRRs

Variable	Unit	Description
		that have not settled.
j	none	A source Settlement Point
k	none	A sink Settlement Point
h	none	An Operating Hour of (i) the remaining hours in the current month and (ii) all hours in the following month.
o	none	A CRR Owner

(3) The Counter-Party's Future Credit Exposure for all PTP Options (FCEOPT) held by the Counter-Party as owner of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled is calculated as follows.

$$\mathbf{FCEOPT_o = - FMMOPT_o}$$

Where:

$$FMMOPT_o = \sum_{(h)} \sum_{(j,k)} [(W_1 * ACP_{h,(j,k)} + W_2 * TOPTV_{h,(j,k)} + W_3 * FDOPTV_{h,(j,k)} + W_4 * PMOPTV_{h,(j,k)}) * OPTMW_{o,h,(j,k)}]$$

$FCEOPT_o$ is calculated using PTP Options registered in the name of the Counter-Party only for (a) the remaining hours of the current month and (b) all hours in the following month.

The above variables are defined as follows:

Variable	Unit	Description
$FCEOPT_o$	$	*Future Credit Exposure for PTP Options* - Counter-Party Future Credit Exposure for all PTP Options held by the Counter-Party as owner *o* of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled.
$FMMOPT_o$	$	*Forward Mark-to-Market for PTP Options* – Estimate of the forward mark-to-market value of PTP Options held by the Counter-Party as owner *o* of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled.
$ACP_{h,(j,k)}$	$/MW per hour	*Auction Clearing Price* - The auction clearing price of the PTP Option with the source *j* and the sink *k* for the hour *h*.
$W_1 – W_4$	none	*Weighting*—The weighting associated with the pricing components that sum to 1. The values of these factors must be determined by the Credit Working Group and posted on the MIS Public Area. The weighting factors may be customizable for the month to which a CRR applies.
$TOPTV_{h,(j,k)}$	$/MW per hour	*Today's PTP Option Value* – The greater of zero or the difference in current day's most recent DAM Settlement Point Price between the sink *k* and the source *j* of the CRR for the hour *h* owned. If the DAM is executed but specific DAM Settlement Point Prices are not available, ERCOT may use the appropriate Hub prices instead.

Variable	Unit	Description
		If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$FDOPTV_{h, (j,k)}$	$/MW per hour	*Five-day PTP Option Value* – Average of the most recent rolling five-day amount given by the greater of zero or the difference in DAM Settlement Point Price between the sink *k* and the source *j* of the CRR for the hour *h* owned. If the DAM is executed but specific DAM Settlement Point Prices are not available, ERCOT may use the appropriate Hub prices instead. If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$PMOPTV_{h, (j,k)}$	$/MW per hour	*Previous Month's PTP Option Value* – Average of the previous month's daily amount given by the greater of zero or the difference in DAM Settlement Point Price between the sink *k* and the source *j* of the CRR for the hour *h* owned. If the DAM is executed but specific DAM Settlement Point Prices are not available, ERCOT may use the appropriate Hub prices instead. If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$OPTMW_{o, h, (j,k)}$	MW	PTP Option with the source *j* and the sink *k* owned by the Counter-Party as owner *o* for hour *h* of: (i) the remaining hours in the current month and (ii) all hours in the following month..
j	none	A source settlement point
k	none	A sink settlement point
h	none	An operating hour of; (i) the remaining hours in the current month and (ii) all hours in the following month
o	none	A CRR owner

(4) The Counter-Party's Future Credit Exposure for all FGRs (FCEFGR) held by the Counter-Party as owner of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled is calculated as follows.

$$\mathbf{FCEFGR_o = - FMMFGR_o}$$

Where:

$$FMMFGR_{\mathbf{o}} = \sum_{(h)} \sum_{(f)} [(W_1 * ACP_{h,\, f} + W_2 * TFGRV_{h,\, f} + W_3 * FDFGRV_{h,\, f} + W_4 * PMFGRV_{h,\, f}) * FGRMW_{o, h, f}]$$

$FCEFGR_o$ is calculated using FGRs registered in the name of the Counter-Party only for:

(a) The remaining hours of the current month and

(b) All hours in the following month.

The above variables are defined as follows:

Variable	Unit	Description
$FCEFGR_o$	$	*Future Credit Exposure for FGRs* - Counter-Party Future Credit Exposure for all FGRs held by the Counter-Party as owner *o* of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled.
$FMMFGR_o$	$	*Forward Mark-to-Market for FGRs* – Estimate of the forward mark-to-market value of FGRs held by the Counter-Party as owner *o* of record at ERCOT for all Operating Days that have not yet occurred and for CRRs that have not settled.
$ACP_{h,\ f}$	$/MW per hour	*Auction Clearing Price* - The auction clearing price of the FGR on the flowgate *f* for hour *h*.
$W_1 – W_4$	none	*Weighting*—The weighting associated with the pricing components that sum to 1. The values of these factors must be determined by the Credit Working Group and posted on the MIS Public Area. The weighting factors may be customizable for the month to which a CRR applies.
$TFGRV_{h,\ f}$	$/MW per hour	*Today's FGR Value* – The current day's most recent DAM price of the FGR on the flowgate *f* for the hour *h*. If the DAM is not executed for an operating day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$FDFGRV_{h,\ f}$	$/MW per hour	*Five-day FGR Value* – Average of the most recent rolling five-day price of the FGR on the flowgate *f* for the hour *h*. If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$PMFGRV_{h,\ f}$	$/MW per hour	*Previous Month's FGR Value* – Average of the previous month's daily price of the FGR on the flowgate *f* for the hour *h*. If the DAM is not executed for an Operating Day, ERCOT shall use the Real Time Market Settlement Point Prices for that Operating Day.
$FGRMW_{o,\ h,\ f}$	MW	FGR on the flowgate *f* owned by the Counter-Party as owner *o* for hour *h* of (a) the remaining hours in the current month and (b) all hours in the following month.
f	none	A Flowgate Right
h	none	An Operating Hour of (a) the remaining hours in the current month and (b) all hours in the following month.
o	none	A CRR Owner

16.11.4.6 Determination of Counter-Party Available Credit Limit

ERCOT shall calculate an Available Credit Limit (ACL) for each Counter-Party equal to 90% of the net of its:

(a) Unsecured Credit Limit; plus

(b) Collateral; minus

(c) TPE.

16.11.4.6.1 Credit Requirements for CRR Auction Participation

(1) Each Counter-Party participating in any CRR Monthly, Annual or other auction as permitted by Sections 16.11.6.1.4, Repossession of CRRs by ERCOT, and 16.11.6.1.5, Declaration of Forfeit of CRRs, shall communicate to ERCOT the credit limit it would like to establish for the CRR Auction no later than three Business Days prior to the close of the CRR bid submission window.

(2) ERCOT shall assign the credit limit for each Counter-Party participating in any CRR Auction as the lower of 90% of ACL or the Counter-Party's requested credit limit no later than two Business Days prior to the close of the CRR bid submission window. ERCOT, in its sole discretion, may increase the credit limit until the close of the CRR bid submission window.

(3) ERCOT shall impose a credit limit in awarding bids and offers in the CRR Auction as described in Section 7.5.5.3, Auction Process.

16.11.4.6.2 Credit Requirements for DAM Participation

(1) ERCOT shall impose a credit limit on each Counter-Party participating in the DAM as the difference between 90% of the ACL and any CRR Auction credit limit assigned.

(2) ERCOT shall impose the credit limit for DAM Participation calculated in item (1) above on the Counter-Party's QSEs and all Subordinate QSEs combined participation in the DAM as described in Section 4.4.10, Credit Requirement for DAM Bids and Offers.

16.11.5 Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT

(1) ERCOT shall monitor the creditworthiness and credit exposure of each Counter-Party or its guarantor, if any. To enable ERCOT to monitor creditworthiness, each Counter-Party shall provide to ERCOT:

(a) Its own or its guarantor's quarterly (semi-annually, if the guarantor is foreign and rated by a rating agency acceptable to ERCOT) unaudited financial statements not later than 60 days (90 days if the guarantor is foreign and rated by a rating agency acceptable to ERCOT) after the close of each of the issuer's fiscal quarters; if an issuer's financial statements are publicly available electronically and the issuer provides to ERCOT sufficient information to access those financial statements, then the issuer is considered to have met this requirement.

(b) Its own or its guarantor's annual audited financial statements not later than 120 days after the close of each of the issuer's fiscal year; if an issuer's financial statements are publicly available electronically and the issuer provides to ERCOT sufficient information to access those financial statements, then the issuer is considered to have met this requirement. ERCOT may extend the period for providing interim unaudited or annual audited statements on a case-by-case basis.

(c) Notice of a material change. A Counter-Party that has been granted an Unsecured Credit Limit pursuant to Section 16.11.2, Requirements for Setting a Counter-Party's Unsecured Credit Limit, shall inform ERCOT within one Business Day if it has experienced a material change in its operations, financial condition or prospects that might adversely affect the Counter-Party and require a revision to its Unsecured Credit Limit. ERCOT may require the Counter-Party to meet one of the credit requirements of Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirements.

(2) A Counter-Party that meets all or part of its creditworthiness requirements using a method provided in Section 16.11.3, is responsible, at all times, for maintaining Financial Security in an amount equal to or greater than that Counter-Party's TPE minus its Unsecured Credit Limit. ERCOT shall promptly notify each Counter-Party of the need to increase its Financial Security, and allow the Counter-Party time as defined in paragraph (3)(a) below to provide additional Financial Security to maintain compliance with this subsection.

(a) When the Counter-Party's TPE as defined in Section 16.11.4, Determination and Monitoring of Counter-Party Credit Exposure, reaches 90% of its Financial Security, ERCOT shall use reasonable efforts to electronically issue a warning to the Counter-Party's Authorized Representative and Credit Contact advising the Counter-Party that it should consider increasing its Financial Security. However, failure to issue that warning does not prevent ERCOT from exercising any of its other rights under this Section.

(b) ERCOT may suspend a Counter-Party when that Counter-Party's TPE as defined in Section 16.11.4, equals or exceeds 100% of the sum of its Unsecured Credit Limit and its Financial Security. The Counter-Party is responsible, at all times, for managing its activity within its TPE or increasing its Financial Security to avoid reaching its limit. Any failure by ERCOT to send a notice as set forth in this Section does not relieve the Counter-Party from the obligation to maintain Financial Security in an amount equal to or greater than that Counter-Party's TPE as defined in Section 16.11.4.

(3) To the extent that a Counter-Party fails to maintain Financial Security in an amount equal to or greater than its TPE as defined in Section 16.11.4:

(a) ERCOT shall promptly notify the Counter-Party, on a Business Day, of the amount by which its Financial Security must be increased and allow it

(i) Until 1500 on the second Bank Business Day from the date on which ERCOT delivered the notice to increase its Financial Security if ERCOT delivered its notice before 1500 on a Business Day, or

(ii) Until 1700 on the second Bank Business Day from the date on which ERCOT delivered notification to increase its Financial Security if ERCOT delivered its Notice after 1500 but prior to 1700 on a Business Day.

ERCOT shall notify the QSE's authorized representative(s) and credit contact if it has not received the required security by 1530 on the Bank Business Day on which the security was due; however, failure to notify the Counter-Party's representatives or contact that the required security was not received does not prevent ERCOT from exercising any of its other rights under this Section.

(b) At the same time it notifies the Counter-Party that is the QSE, ERCOT may notify each LSE and Resource represented by the Counter-Party that the LSE or Resource may be required to designate a new QSE if its current QSE fails to increase its Financial Security.

(c) ERCOT is not required to make any payment to that Counter-Party unless and until the Counter-Party increases its Financial Security. The payments that ERCOT will not make to a Counter-Party include Invoice receipts, CRR Revenues, CRR Credits, reimbursements for short payments, and any other reimbursements or credits under any other agreement between the Market Participant and ERCOT. ERCOT may retain all such amounts until the Counter-Party has fully discharged all payment obligations owed to ERCOT under the Counter-Party Agreement, other agreements, and these Protocols.

(d) ERCOT may reject any bids or offers in a CRR Auction from the Counter-Party until it has increased its Financial Security. ERCOT may reject any bids or offers from the Counter-Party in the Day-Ahead Market until it has increased its Financial Security.

(4) If a Counter-Party increases its Financial Security by the deadline in paragraph (3)(a) above, then ERCOT may notify each LSE and Resource represented by the Counter-Party.

(5) If a Counter-Party increases its Financial Security by the deadline in paragraph (3)(a) above, then ERCOT shall release any payments held.

16.11.6 Payment Breach and Late Payments by Market Participants

(1) It is the sole responsibility of each Market Participant to ensure that the full amounts due to ERCOT, or its designee, if applicable, by that Market Participant, is paid to ERCOT by close of the Bank Business Day on which it is due.

(2) If a Market Participant receives separate Invoices for Subordinate QSE or various CRR Account Holder activity, netting by the Market Participant of the amounts due to ERCOT with amounts due to the Market Participant among those Invoices for payment purposes is not permitted. The amounts due to ERCOT on the separate Invoices for each Market Participant must be paid by the close of the Bank Business Day on which it is due. If a Market Participant does not pay the full amount due to ERCOT for all such Invoices by the required time, ERCOT shall deduct any and all amounts due and unpaid from any

amounts due to the same Market Participant before allocating short payments to other Market Participants.

(3) The failure of a Market Participant to pay when due any payment or Financial Security obligation owed to ERCOT or its designee, if applicable, under any agreement with ERCOT, is an event of "Payment Breach." Any Payment Breach by a Market Participant under any agreement with ERCOT is a default under all other agreements between ERCOT and the Market Participant. Upon a Payment Breach, ERCOT shall immediately attempt to contact an Authorized Representative and Credit Contact of the Market Participant telephonically and shall send appropriate written notices, as described below, and demand payment of the past due amount.

(4) Upon a Payment Breach, ERCOT may impose the below-listed remedies for Payment Breach ("Default Breach"), as set forth in Section 16.11.6.1, ERCOT's Remedies , in addition to any other rights or remedies ERCOT has under any agreement, the Protocols or at common law. If a Market Participant makes a payment or a partial payment as allowed by these Protocols or a collateral call to ERCOT after the due date and time, that payment is a "Late Payment," regardless of the reason it was late. If ERCOT receives, within two Bank Business Days after the due date, a Late Payment that fully pays the Market Participant's payment obligation or Financial Security obligation, ERCOT may waive the Payment Breach, except for ERCOT's remedies in Section 16.11.6.2, ERCOT's Remedies for Late Payments by a Market Participant. Even if ERCOT chooses to not immediately impose Default Remedies against a Market Participant because it has fully paid its obligation within two Bank Business Days, ERCOT shall track the number of Late Payments received from each Market Participant in each rolling 12-month period for purposes of imposing the Late Payment remedies set forth in Section 16.11.6.2.

16.11.6.1 ERCOT's Remedies

In addition to all other remedies that ERCOT has under any agreement, common law or these Protocols, for Payment Breaches or other defaults by a Market Participant, ERCOT has the following additional remedies.

16.11.6.1.1 No Payments by ERCOT to Market Participant

ERCOT is not required to make any payment to a Market Participant unless and until the Market Participant cures the Payment Breach by paying the past due amount in full, including amounts due under Section 16.11.6.1.3, Aggregate Amount Owed by Breaching Market Participant Immediately Due. The payments that ERCOT will not make include Invoice receipts, CRR Auction revenues, CRR credits, reimbursements for short payments and any other reimbursements or credits under any and all other agreements between ERCOT and the Market Participant. ERCOT shall retain all such amounts until the Market Participant has fully paid all amounts owed to ERCOT under any agreements and these Protocols. If the Market Participant should fail to pay the full amount due within the cure period, ERCOT may apply all funds it withheld toward the payment of the delinquent amount(s).

16.11.6.1.2 ERCOT May Draw On, Hold or Distribute Funds

Upon a Payment Default, ERCOT, at its option, without notice to the Market Participant and in its sole discretion, may immediately, or at any time before the Market Participant pays the past due amount in full, including amounts due under Section 16.11.6.1.3, Aggregate Amount Owed by Breaching Market Participant Immediately Due, draw on, hold or distribute to other Market Participants any Financial Security or other funds of the Market Participant in ERCOT's possession. If the funds drawn exceed the amount applied to any Payment Breach, then ERCOT may hold those funds as Financial Security.

16.11.6.1.3 Aggregate Amount Owed by Breaching Market Participant Immediately Due

ERCOT shall aggregate all amounts due it by the Market Participant under any agreement with ERCOT and the Protocols into a single amount to the fullest extent allowed by law. The entire unpaid net balance owed to ERCOT by the Market Participant, at ERCOT's option, and its sole discretion, is immediately due and payable without further notice and demand for payment. Any such notice and demand for payment are expressly waived by the Market Participant.

16.11.6.1.4 Repossession of CRRs by ERCOT

ERCOT, at its sole discretion, may repossess CRRs held by a Market Participant with an uncured Payment Breach. ERCOT shall effect that repossession by sending a written notice to the Market Participant of the repossession and by removing the CRRs from the Market Participant's CRR account. ERCOT shall offer all of those repossessed CRRs, with each repossessed CRR in its existing configuration, in a one-time auction to Market Participants (other than the Market Participant(s) in Payment Breach) for sale to the highest bidder. ERCOT shall offset net revenues from that sale against amounts owed to ERCOT by the Market Participant. If ERCOT receives no bids for a CRR in that auction, ERCOT shall void the CRR and may not model it in all future DAMs and CCR Auctions.

16.11.6.1.5 Declaration of Forfeit of CRRs

(1) At ERCOT's sole discretion, if it does not receive full payment on the due date of a CRR Auction Invoice, may declare any of the CRR Bids cleared and PCRRs allocated to the Market Participant forfeited. ERCOT shall effect that forfeiture by sending a written notice to the Market Participant of the forfeiture and of not delivering the CRRs or PCRRs to the Market Participant's CRR account. ERCOT shall offer all forfeited CRRs, with each forfeited CRR in its existing configuration, in a one-time auction to Market Participants (other than the Market Participant(s) in Payment Breach) for sale to the highest bidder or ERCOT shall make the related capacity available in subsequent CRR auctions. Revenue from that sale shall be considered as CRR Auction revenue and distributed to QSEs based on Load Ratio Share as specified in Section 7.5.7, Method for Distributing CRR Auction Revenues.

(2) ERCOT may also, at its sole discretion, honor any of the Offers from Market Participants that were cleared in the CRR auction by removing the CRRs from the Market Participant's CRR account. ERCOT shall offset net revenues due to the Market Participant from CRRs Offered and cleared against amounts owed to ERCOT by the Market Participant.

16.11.6.1.6 Revocation of a Market Participant's Rights and Termination of Agreements

(1) ERCOT may revoke a breaching Market Participant's rights to conduct activities under these Protocols. ERCOT may also terminate the breaching Market Participant's agreements with ERCOT.

(2) If ERCOT revokes a Market Participant's rights or terminates the Market Participant's agreements, then the provisions of Section 16.2.5, Suspended Qualified Scheduling Entity – Notification to LSEs and Resource Entities Represented and Section 16.2.6.1, Designation as an Emergency Qualified Scheduling Entity or Virtual Qualified Scheduling Entity apply.

(3) If a breaching Market Participant is also an LSE (whether or not the default occurred pursuant to the Market Participant's activities as an LSE), then:

(a) within 24 hours of receiving notice of the Payment Breach, the Market Participant shall provide to ERCOT all the information regarding its ESI IDs set forth in the ERCOT Retail Market Guide; and

(b) on revocation of some or all of the Market Participant's rights or termination of the Market Participant's agreements and on notice to the Market Participant and the PUCT, ERCOT shall initiate a mass transition of the Market Participant's ESI IDs pursuant to Section 15.1.2.9, Mass Transition, without the necessity of obtaining any order from or other action by the PUCT.

(4) After revocation of its rights or termination of its Agreement, with ERCOT, the Market Participant will remain liable for all charges or costs associated with any continued activity related to the Counter-Party's relationship with ERCOT and any expenses arising from the consequences of such termination or revocation.

16.11.6.2 ERCOT's Remedies for Late Payments by a Market Participant

If a Market Participant makes any Late Payments, and even if ERCOT does not immediately implement the above-referenced remedies for any Payment Default by a Market Participant, the Market Participant is subject to the following actions.

16.11.6.2.1 First Late Payment in Any Rolling 12-Month Period

For the first Late Payment in any rolling 12-month period, ERCOT shall review the circumstances and reason for the Late Payment, and shall, at its sole discretion, determine whether it should take Level I Enforcement action against the Market Participant. ERCOT shall send written notice to the Market Participant's Authorized Representative and Credit Contact, advising the Market Participant whether or not ERCOT is taking Level I Enforcement action, and advising the Market Participant of the action required under Level I Enforcement, if applicable.

16.11.6.2.2 Second Late Payment in Any Rolling 12-Month Period

For the second Late Payment in any rolling 12-month period, ERCOT shall review the circumstances and reason for the Late Payment, and shall take action as follows:

(a) If ERCOT did not take Level I Enforcement action in the case of the first Late Payment, ERCOT shall take Level I Enforcement action related to this Late Payment.

(b) If ERCOT did take Level I Enforcement action in the case of the first Late Payment, ERCOT shall take Level II Enforcement action related to this Late Payment.

(c) ERCOT shall send written notice to the Market Participant's Authorized Representative and Credit Contact, advising the Market Participant of the action required under Level I or Level II Enforcement.

16.11.6.2.3 Third Late Payment in Any Rolling 12-Month Period

For the third Late Payment in any rolling 12-month period, ERCOT shall review the circumstances and reason for the Late Payment, and shall take action as follows:

(a) If ERCOT did not take Level II Enforcement action in the case of the second Late Payment, ERCOT shall take Level II Enforcement action related to this Late Payment.

(b) If ERCOT did take Level II Enforcement action in the case of the second Late Payment, ERCOT shall take Level III Enforcement action related to this Late Payment.

(c) ERCOT shall send written notice to the Market Participant's Authorized Representative and Credit Contact advising the Market Participant of the action required under Level II or Level III Enforcement.

16.11.6.2.4 Fourth and All Subsequent Late Payments in Any Rolling 12-Month Period

For the fourth and all subsequent Late Payments in any rolling 12-month period:

(a) ERCOT shall take Level III Enforcement action related to the Late Payment.

(b) ERCOT shall send written notice to the Market Participant’s Authorized Representative and Credit Contact advising the Market Participant of the action required under Level III Enforcement.

16.11.6.2.5 Level I Enforcement

Under Level I Enforcement, ERCOT shall notify the Market Participant to comply with one of the following requirements; whichever is appropriate in ERCOT’s sole discretion:

(a) If the Market Participant has not provided Financial Security, the Market Participant shall now provide Financial Security, within two Bank Business Days, in an amount at or above 110% of the amount of the Market Participant’s TPE less the Unsecured Credit Limit; or any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

(b) If the Market Participant has already provided Financial Security, the Market Participant shall increase its Financial Security, within two Bank Business Days, to an amount at or above 110% of its TPE less the Unsecured Credit Limit or any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region, whichever applies.

Increased Financial Security requirements under this Section remain in effect for a minimum of 60 days and remain in effect thereafter until ERCOT, at its sole discretion, determines to reduce such Financial Security requirements to the normally applicable levels.

16.11.6.2.6 Level II Enforcement

Under Level II Enforcement, ERCOT shall notify the Market Participant to comply with the following requirements and may meet with the Market Participant’s Authorized Representative and Credit Contact to discuss the Late Payment occurrences:

(a) Under Level II Enforcement, the Market Participant shall provide Financial Security, within two Bank Business days, in the form of a cash deposit or letter of credit, as chosen by ERCOT at its sole discretion, at 110% of the Market Participant’s TPE less the Unsecured Credit Limit or for any other liability to ERCOT that the Market Participant has or is expected to have for activity in the ERCOT Region.

(b) Increased Financial Security requirements under this Section remain in effect for a minimum of 60 days and remain in effect thereafter until ERCOT, at its sole discretion, determines to reduce such Financial Security requirements to the normally applicable levels.

16.11.6.2.7 Level III Enforcement

ERCOT shall make reasonable efforts to meet with a Market Participant's Authorized Representative and Credit Contact to discuss the Late Payment occurrences. ERCOT shall take one or more of the following actions:

(a) Advise the Authorized Representative and Credit Contact that a subsequent Late Payment in the rolling 12-month period could result in termination of the Market Participant's right to act as a Market Participant in the ERCOT Region; or

(b) Take action under Section 16.11.6.1.6, Revocation of a Market Participant's Rights and Termination of Agreement.

16.11.6.3 Late Payment Fee

(1) A Market Participant shall pay late fees, together with any related transaction costs incurred by ERCOT, on any delinquent amount to ERCOT according to the late fee terms for the period from and including the original due date for the payment to the date on which ERCOT actually receives the payment.

(2) Late Payment revenues from Market Participants, less ERCOT's transaction costs, must be included in the annual or monthly auction revenues and distributed in accordance with Section 7.5.7, Method for Distributing CRR Auction Revenues.

16.11.7 Release of Market Participant's Financial Security Requirement

Following the termination of a Market Participant's Agreement, ERCOT shall, within 30 days after being satisfied, in its sole discretion, that no sums remain owing or will become due and payable by the Market Participant under these Protocols or any agreement between the Market Participant and ERCOT, return or release to the Market Participant, as appropriate, any Financial Security still held by ERCOT that the Market Participant provided to ERCOT under this Section.

16.11.8 Acceleration

Upon termination of a Market Participant's rights as a Market Participant and any other agreement(s) between ERCOT and the Market Participant, all sums owed to ERCOT are immediately accelerated and are immediately due and owing in full. At that time, ERCOT may immediately draw upon the Market Participant's Financial Security and shall use those funds to offset or recoup all amounts due to ERCOT.

16.12 User Security Administrator and Digital Certificates

Each Market Participant is allowed access to ERCOT's computer systems through the use of Digital Certificates. A "Digital Certificate" is an electronic file installed on a programmatic interface or an individual's assigned computer used to authenticate that the interface or individual is authorized for secure electronic messaging with ERCOT's computer systems. Digital Certificates expire after one year. A User Security Administrator (USA) is responsible for managing the Market Participant's access to ERCOT's computer systems through Digital Certificates. Each Market Participant must, as part of the application for registration with ERCOT, designate an individual employee or authorized agent as its USA, and optionally, a secondary USA. If a Market Participant has designated a secondary USA, the secondary USA functions in the same manner as the primary USA. The Market Participant is responsible for revising its USA list as the need arises. The Market Participant's USA is also responsible for registering all Market Participant's Digital Certificate holders ("Certificate Holders") and administering the use of Digital Certificates on behalf of the Market Participant. Each Market Participant with more than one ERCOT functional registration must designate a USA for each registration (which may be the same employee or authorized agent) and shall manage each registration separately for the purposes of this Section. Once the Market Participant completes registration requirements, ERCOT shall send the USA a copy of "Digital Certificate Introduction and Use for Market Participants." This document is a guide for the USA containing Digital Certificate procedures.

16.12.1 USA Responsibilities and Qualifications for Digital Certificate Holders

The USA and the Market Participant are responsible for the following:

(a) Requesting Digital Certificates for authorized potential Certificate Holders (either persons or programmatic interfaces) that the USA has qualified through an appropriate screening process requiring confirmation that the Certificate Holder is an employee or authorized agent (including third parties) of the Market Participant. A Certificate Holder (including the USA) must be qualified as set forth below. The Market Participant shall be liable for ensuring that each of its Certificate Holder(s) meets the requirements of (i) – (v) below.

(i) For any employee or authorized agent receiving a Digital Certificate, the Market Participant shall confirm that the employee or authorized agent satisfies reasonable background review sufficient for employment or contract with the Market Participant so as to reasonably limit threat(s) to ERCOT's market or computer systems. The Market Participant may not request that Digital Certificates be issued to any employee or authorized agent it determines, after reasonable background review, that the employee or authorized agent poses a threat to ERCOT's market or computer systems. If the Market Participant does not use a background review process at the time this Section first becomes applicable to the Market Participant (i.e., upon registration with ERCOT for new Market Participants), the Market Participant shall institute a process to require reasonable background reviews for the potential Certificate Holders no later than six months after this Section first applies to the Market Participant.

(ii) The potential Certificate Holder is aware of the rules and restrictions relating to the use of Digital Certificates.

(iii) The potential Certificate Holder is eligible to review and receive technology and software under applicable export control laws and regulations and under the Foreign Corrupt Practices Act. Information for web-listings must be located on the MIS Public Area. If the Market Participant does not use an export control and Foreign Corrupt Practices Act review process at the time this Section first applies to the Market Participant, the Market Participant shall institute a process to require such reviews for potential Certificate Holders no later than six months after this Section first applies to the Market Participant.

(iv) The Market Participant has conducted a reasonable review of the potential Certificate Holder and is not aware that the potential Certificate Holder is one of the persons on any U.S. terrorist watch list, the link to which is located on the MIS Public Area. If the Market Participant does not use a terrorist watch list review process at the time this Section first applies to the Market Participant, the Market Participant shall institute a process to require such reviews for potential Certificate Holders no later than six months after this Section first applies to the Market Participant.

(v) The Certificate Holder does not violate the conditions of use specified by the software vendor that provides the Digital Certificates for the Market Participant's use and provided to the Certificate Holder.

(b) Requesting revocation of Digital Certificates under any of the following conditions:

(i) As soon as possible but no later than three Business Days after:

(A) A Certificate Holder ceases employment with the Market Participant; or

(B) The Market Participant becomes aware that a Certificate Holder is changing job functions (pursuant to a reasonable process for identifying when job function changes occur) so that the Certificate Holder no longer needs the Digital Certificate,

The Market Participant or USA shall request the revocation by proceeding with the ERCOT certificate revocation process.

(ii) As soon as possible, but no later than five Business Days, after the Market Participant becomes aware (pursuant to a reasonable process for identifying violations) that the Certificate Holder has violated any of the following conditions of use of a Digital Certificate, the Market Participant or USA shall request the revocation by proceeding with the ERCOT certificate revocation process. Violations of conditions of use include:

(A) Violating the requirements of Section 16.12.1(a) above; or

(B) Using the Digital Certificate for any unauthorized purpose; or

(C) Allowing any person other than the Certificate Holder to use the Digital Certificate.

(c) Managing the level of access for each Certificate Holder by assigning and maintaining Digital Certificate roles for each authorized user in accordance with the process set forth in "Digital Certificate Introduction and Use for Market Participants."

(d) Requesting annual renewal of Digital Certificates.

(e) If needed, issuing Digital Certificates for use by electronic systems not limited to servers.

(f) Maintaining the integrity of the administration of Digital Certificates through consistent, sound and reasonable business practices.

16.12.2 Requirements for Use of Digital Certificates

Use of Digital Certificates must comply with the following:

(a) A Digital Certificate shall be used by only one individual and may not be shared. If multiple employees or authorized agents share a computer and each requires a Digital Certificate, the USA shall request separate Digital Certificates for each. Multiple Digital Certificates may be installed and managed on a single computer. ERCOT shall include instructions on how to manage multiple Digital Certificates in "Digital Certificate Introduction and Use for Market Participants."

(b) Electronic equipment on which the Digital Certificate resides must be physically and electronically secured in a reasonable manner to prevent improper use of the Digital Certificate.

(c) The Market Participant is wholly responsible for any use of Digital Certificates issued by its USA.

16.12.3 Market Participant Audits of User Security Administrators and Digital Certificates

(1) During September of each year, each Market Participant shall generate a list of its registered USA and Certificate Holders. The Market Participant, through its USA or

another authorized third party, shall perform an audit by reviewing the list and noting any inconsistencies or instances of non-compliance (including, for example, any Certificate Holder that may have changed job functions and no longer requires the Digital Certificate). If the Market Participant or its USA or the authorized third party identifies discrepancies, the USA shall use the process for managing Digital Certificates as included in "Digital Certificate Introduction and Use for Market Participants" to rectify the discrepancy. The audit must, at a minimum confirm that:

(a) The Market Participant and each listed USA and Certificate Holder meet the applicable requirements of Section 16.12.1(a) and (b);

(b) Each listed USA and Certificate Holder is currently employed by or is an authorized agent contracted with the Market Participant;

(c) The Market Participant has verified that the listed USA is authorized to be the USA;

(d) Each Certificate Holder is authorized to retain and use the Digital Certificate; and

(e) Each listed Certificate Holder needs the Digital Certificate to perform his or her job functions.

(2) By October 1 of each year, a Market Participant shall submit to ERCOT an attestation from an officer or executive with authority to bind the Market Participant, certifying that:

(a) The Market Participant has complied with the requirements of the audit;

(b) The Market Participant has verified that all assigned Digital Certificates belong to Certificate Holders authorized by the Market Participant's USA. If the Certificate Holders no longer meet the criteria in Section 16.12.1(a), the USA shall inform ERCOT as described in Section 16.12.1(b) and note the findings in the response; and

(c) The USA and all Certificate Holders have been qualified through a reasonable screening process.

(3) If a Market Participant cannot comply with the October 1 deadline at the time this Section first applies to the Market Participant, the Market Participant shall request an extension of the deadline by providing ERCOT a written explanation of why it cannot meet the deadline. The explanation must include a plan and timeline for compliance not to exceed six months from the original deadline. ERCOT shall review that extension request and notify the Market Participant if the request is approved or denied. ERCOT may approve no more than one extension request per Market Participant.

(4) By December 1 of each year, ERCOT shall acknowledge receipt of each Market Participant audit received and indicate whether any required information is missing from the audit.

16.12.4 ERCOT Audit - Consequences of Non-compliance

(1) ERCOT, or its designee, shall review the audit results submitted under Section 16.12.3, Market Participant Audits of User Security Administration and Digital Certificates, and may audit the Market Participant for compliance with the provisions of this Section 16.12, User Security Administrator and Digital Certificates. The Market Participant shall cooperate fully with ERCOT in such audits.

(2) On or about December 15 of each year, ERCOT shall report to the PUCT all Market Participants failing to properly perform annual audits as described in Section 16.12.3 or non-compliance with Section 16.12.3.

(3) Subject to the requirements of item (4) below, ERCOT, after providing notice to the Market Participant and the PUCT, may disqualify the Market Participant’s USA and/or revoke any or all Digital Certificates assigned by that USA, if:

(a) The Market Participant does not properly and timely perform the audit;

(b) ERCOT discovers non-compliance; or

(c) The Market Participant does not timely request revocation of its Digital Certificates for unauthorized Certificate Holders.

(4) ERCOT may not disqualify a Market Participant’s USA or revoke a Market Participant’s Digital Certificate(s) without first giving the Market Participant the following options:

(a) Opportunity to work with ERCOT to resolve issues in a manner agreeable to both parties;

(b) Opportunity to authorize a new USA and assign new Digital Certificates as necessary to prevent disruption of the Market Participant’s business; and

(c) If the Market Participant is not willing or cannot designate a new USA or the violation is so egregious that ERCOT determines that it is inappropriate to issue new Digital Certificates, the opportunity to appeal ERCOT’s decision to disqualify the Market Participant’s USA and revoke its Digital Certificates to the PUCT.

16.13 Registration of Emergency Interruptible Load Service (EILS)

EILS Loads shall register with ERCOT by completing and signing Appendix A, Acknowledgement by EILS Load Owning or Controlling Entity, of Section 22K, Standard Form Emergency Interruptible Load Service (EILS) Agreement.

ERCOT Nodal Protocols

Section 17: Market Monitoring and Data Collection

Updated: February 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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17 MARKET MONITORING AND DATA COLLECTION

17.1 Overview

The Public Utility Commission of Texas (PUCT), with the assistance of the Independent Market Monitor (IMM) established in accordance with PUCT rules, has the ultimate responsibility for market oversight in ERCOT. ERCOT shall assist the PUCT and the IMM by performing the data collection functions specified in this Section.

17.2 Objectives and Scope of Market Monitoring Data Collection

The market monitoring data collection is designed to assist the PUCT and Independent Market Monitor (IMM) to:

(a) Protect Market Participants and Customers from the exercise of market power and from market manipulations;

(b) Ensure that there is effective and persistent competition for events that are not mitigated;

(c) Ensure that the market design and implementation are efficient;

(d) Guard against inefficiencies in the market and market manipulations;

(e) Ensure a justifiable and reasonable price impact; and

(f) Ensure that data posted on the MIS Public Area fulfills the objective of transparency of market information consistent with Section 1.3, Confidentiality.

17.3 Market Data Collection and Use

ERCOT shall establish procedures to ensure that the PUCT staff and Independent Market Monitor (IMM) may access all data maintained by ERCOT and deemed necessary by the PUCT staff and IMM to perform its market oversight activities, pursuant to subsection (e) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance. The following sections explain the collection, handling, verification, and retention of information by ERCOT that is accessible by the PUCT staff and IMM.

17.3.1 Information System Data Collection and Retention

ERCOT shall develop and operate an information system to collect and to store data required by these Protocols. ERCOT shall provide adequate communication equipment and necessary software packages to enable the PUCT staff and the IMM to establish electronic access to the information system and to facilitate the development and application of quantitative tools necessary for the market monitoring function. Data from source systems must be replicated near Real Time and available for remote query by the PUCT staff and the IMM until data is available in the Data Archive and Data Warehouse. The Data Warehouse and Data Archive must be designed to accommodate a remote query function by the PUCT staff and the IMM at any time.

17.3.2 Data Categories and Handling Procedures

ERCOT shall develop, and refine based on experience, a detailed catalog of all data categories that it can acquire and the procedures that it will use to handle such data, including procedures for protecting Protected Information. This catalog must include documentation of the meaning of the data elements, and must be updated upon any change in systems (e.g. EMMS or settlements) that affect the data elements or interpretation of these elements.

17.3.3 Accuracy of Data Collection

(1) ERCOT shall continuously apply appropriate procedures for the accurate collection of data into the Data Warehouse and accurate communication of that data for use by the PUCT staff and IMM. By written notice, ERCOT may require Market Participants to verify the accuracy of data previously submitted to ERCOT.

(2) ERCOT shall report to the PUCT and IMM any failure by a Market Participant to provide accurate and complete information in the manner and time requested under these Protocols, and that failure may be treated as grounds for action against the Market Participant.

(3) ERCOT shall cause to be performed an annual audit of ERCOT data, data collection, and data documentation for adequacy and accuracy. The auditor will provide recommendations to address potential areas of improvements.

17.3.4 PUCT Staff and IMM Review of Data Collection

The PUCT staff and IMM may review the catalogs of information and data collection verification criteria, developed by ERCOT according to these Protocols, and may propose such changes, additions, or deletions to the catalogs and criteria as it sees fit. In so doing, the PUCT staff or IMM may require database items or evaluation criteria to be included in the pertinent catalogs.

17.3.5 Data Retention

Data stored in the Data Warehouse and Data Archive must be available online for four (4) years from ERCOT's creation or receipt of the data. Data stored in the Data Archive must be maintained by ERCOT for a total of seven years from ERCOT's creation or receipt of the data.

17.4 Provision of Data to Individual Market Participants

Data requested by a Market Participant that is not available to the requesting Market Participant via the MIS may be provided by ERCOT to the requesting Market Participant on approval of the ERCOT CEO or designee and subject to constraints on ERCOT's resources, but this Section is not an authorization to release Protected Information of other Entities. Where answering the request imposes a burden or expense on ERCOT, the data may be provided on the condition that a reasonable contribution to ERCOT for its cost incurred is made by the requesting Market Participant according to the ERCOT service fee schedule posted on the MIS Public Area. ERCOT shall accommodate these requests on a nondiscriminatory basis.

17.5 Reports to PUCT Staff, IMM, and the FERC

(1) ERCOT shall make data available to the PUCT staff and Independent Market Monitor (IMM) in a nightly report. PUCT staff or IMM may require, after consultation with ERCOT, changes to the form of the nightly report, reasonably limited to data ERCOT is able to collect.

(2) ERCOT staff shall develop a schedule and format for reports to the PUCT staff, IMM, and the Federal Energy Regulatory Commission (FERC) as required. ERCOT staff shall prepare and submit the reports according to the schedule approved by the ERCOT Board, the PUCT staff and IMM.

17.6 Changes to Facilitate Market Operation

ERCOT shall evaluate its system operation and market performance to identify potential areas for improvements. This evaluation must consider impacts on system operations and market performance of PUCT rules, these Protocols, Operating Guides, and any other ERCOT operating procedures. Upon identification of areas that require improvements, ERCOT shall take appropriate actions to make those improvements including revising its procedures, proposing changes to these Protocols through the process specified in Section 21, Process for Protocol Revision, and submitting recommendations to the PUCT or other appropriate Governmental Authorities. In performing these tasks, ERCOT shall seek comments and recommendations from the Independent Market Monitor (IMM), PUCT staff, Market Participants, and other interested Entities.

ERCOT Nodal Protocols

Section 18: Load Profiling

Updated: July 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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18 LOAD PROFILING

18.1 Overview

(1) The ERCOT retail market requires a 15-minute Settlement Interval, yet the vast majority of Customers do not have the metering necessary to measure their consumption at this level of granularity. Load Profiling provides a cost-effective way of estimating 15-minute Load for these Customers, enables the accounting of their energy usage in the market Settlement process, and allows the participation of these Customers in the retail market.

(2) This Section details how Load Profiling will be implemented in ERCOT.

18.2 Methodology

(1) ERCOT has developed Load Profiles for both non-interval metered Loads and Non-Metered Loads. A Load Profiling methodology is the fundamental basis on which Load Profiles are created. The implementation of a Load Profiling methodology may require statistical sampling, engineering methods, econometric modeling, or other approaches.

(2) The following Load Profiling methods are used:

Type of Load	**Load Profiling Methodology**
Non-interval metered	Adjusted static models
Non-Metered	Engineering estimates

(3) Load Profiles have also been developed for Interval Data Recorders (IDRs) for use in Settlements when actual IDR data is not available. All Load Profiles shall conform to the ERCOT-defined Settlement Interval length.

(4) Any change from one methodology to another will require approval of the Technical Advisory Committee (TAC), without the necessity of complying with the procedures in Section 21, Process for Protocol Revision. TAC shall establish the implementation date for approved changes, recognizing the magnitude of the impacts on Market Participants.

18.2.1 Guidelines for Development of Load Profiles

In developing Load Profiles, ERCOT shall strive to achieve an optimal combination of the following:

(a) Give no unfair advantage to any Entity;

(b) Maximize usability by minimizing the total number of Load Profiles without compromising accuracy and cost effectiveness;

(c) Minimize the Load Profiles' contribution to Unaccounted For Energy (UFE) over all Settlement Intervals, paying particular attention to higher cost periods;

(d) Reflect reasonably homogenous groups, with respect to Load shape and likely supply costs;

(e) Develop Load Profiles that are distinctly different;

(f) Develop Load Profiles for areas with incomplete Load data utilizing data from other sources, taking into account similarities and differences in Load;

(g) Accommodate Time Of Use (TOU) rate classes;

(h) Use the most accurate Load research data available; and

(i) Develop Load Profiles based on readily identifiable parameters that are not subject to frequent change.

18.2.2 Load Profiles for Non-Interval Metered Loads

Load Profiles for non-interval metered Loads are created using statistical models developed from appropriate Load research sample data. These models are referred to as adjusted static. These model equations relate daily Settlement Interval Load patterns to relevant weather descriptors such as maximum and minimum dry-bulb temperature and humidity. Other daily characteristics such as day-of-the-week and sunrise/sunset times are also employed.

18.2.3 Load Profiles for Non-Metered Loads

Load Profiles for Non-Metered Loads, e.g. streetlights, traffic signals, security lighting, billboards, and parking lots are created using engineering estimates based on known criteria, such as hours of operation, with appropriate variation in sunrise/sunset times. Transmission Service Providers (TSPs) and/or Distribution Service Providers (DSPs) are responsible for providing monthly consumption (kWh) for non-metered Electric Service Identifiers (ESI IDs).

18.2.4 Generic Load Profiles for Interval Data Recorders

(1) Generic or default Load Profiles will be developed for IDRs. These profiles will only be used when no historic Customer-specific interval data is available for Settlements. The adjusted static methodology will be used to create these Load Profiles.

(2) For details on the method to estimate IDR data for Settlement purposes, refer to Section 11, Data Acquisition and Aggregation.

18.2.5 Identification of Weather Zones and Load Profile Types

ERCOT, in coordination with the appropriate TAC subcommittee, will identify Weather Zones and Load Profile Types based on an analysis of the Load research data, weather data, effects of power price changes from interval to interval, and sunrise/sunset data.

18.2.6 Daily Profile Creation Process

ERCOT will maintain Load Profile Models to create profiles for the target Settlement day (backcast) and three days following the current day (forecast). ERCOT will automatically collect actual weather conditions and weather forecasts to enable the creation of the Load Profiles. ERCOT will maintain sunrise/sunset information for creating Load Profiles that require these parameters.

18.2.7 Maintenance of Samples and Load Profile Models

ERCOT, in coordination with TSPs and/or DSPs, shall periodically monitor, review, and maintain the validity and accuracy of the Load research samples and the Load Profiling models. ERCOT shall take the necessary action to alleviate any situations whereby Load Profiles are no longer representative.

18.2.7.1 Sample Maintenance

(1) ERCOT will review Load research sample validity (e.g. difference-of-means test) at the following times:

(a) At least annually, and

(b) When discrepancies (such as excessive UFE) or disputes warrant.

(2) ERCOT will monitor and review this sampling in accordance with ERCOT Protocols, the Load Profiling Guide and the most current Association of Edison Illuminating Companies (AEIC) Load Research manual.

18.2.7.2 Model Maintenance

ERCOT shall monitor the applicability of the Load Profiling models by comparing all available actual interval data samples with estimates generated from the profile model by interval for the same time period. Should these comparisons reveal significant discrepancies, ERCOT should take appropriate action and coordinate with the appropriate TAC subcommittee.

18.2.8 Adjustments and Changes to Load Profile Development

(1) ERCOT and the appropriate TAC subcommittee will conduct an ongoing evaluation of the current Load Profiling methodology. Together they will determine whether appropriate changes to the methodology should be made or whether another approach or combination of approaches is warranted. Any Market Participant may request a review of the Load Profiling methodology. A change from one Load Profiling methodology to another must be approved by TAC, as provided in Section 18.2, Methodology.

(2) Any Market Participant may petition ERCOT for adjustments to the existing Load Profiles and for development of new Load Profiles. The Market Participant making the request shall submit their proposal in writing to ERCOT. ERCOT will post to the Market Information System (MIS) Public Area the request and respond to such requests within 60 days. ERCOT shall coordinate with the appropriate TAC subcommittee for each change request. ERCOT shall strive to make the necessary changes within a reasonable period of time.

(3) ERCOT, in coordination with the appropriate TAC subcommittee, may make changes to existing Load Profiles and establish additional Load Profiles. All changes to Load Profiles shall adhere to these Protocols. When additional Load Profiles are established, ERCOT shall evaluate the impact on existing Load Profiles and associated Load research samples.

(4) A Market Participant may submit a request to ERCOT for conditional approval of a new Load Profile segment following the approval process as specified in the Load Profiling Guide Section 12, Request for Profile Segment Changes, Additions, or Removals. In conjunction with this request, ERCOT shall specify the requirements for additional Load research sampling and shall define specific and objective criteria to be met by the analysis of this Load research data to meet the requirements for final approval. Provided the request for conditional approval has received the appropriate ERCOT committee approval and ERCOT determines the specified criteria are met, the request shall be granted final approval. If ERCOT determines the specified criteria are not met, the request shall be denied.

(5) Section 9.18, Profile Development Cost Recovery Fee for a Non-ERCOT Sponsored Load Profile Segment, describes the process for compensating the originator of a profile segment change request by Retail Electric Providers (REPs) wishing to subscribe to the profile segment.

(6) ERCOT shall give at least 150 days notice to all Market Participants prior to market implementation of any change in Load Profile Methodology, existing Load Profiles, or when any additional Load Profiles are developed. This notice shall include a Load Profile change implementation timeline, which specifies dates on which key events during the Load Profile change process will take place. Upon any change in Load Profile Types, TSPs and/or DSPs shall send any revised Load Profile ID assignments required by the change to the registration system within the implementation timeline. After the new

Load Profile(s) becomes available, changes to Load Profile Types will be effective on the next meter read date for each ESI ID.

(7) If one or more Load Profiles require changes to reduce excessive UFE, as determined by the appropriate TAC subcommittee, TAC may provide a shorter notice period and implementation date, than otherwise provided herein, for such required changes to Load Profiles. If the Load Profile Methodology requires changes to reduce excessive UFE, as determined by the appropriate TAC subcommittee, TAC may provide an expedited notice period and implementation date. TAC may require the standard Load Profile revision process follow such expedited revisions for long-term resolution.

18.2.9 Special Requirement for Profiling Sample Points

When a Premise is used as part of a Load research sample used for Load Profiling, and that Premise or that Premise's Competitive Retailer (CR) elects to use its interval data for Settlement purposes, it will be necessary to replace that Premise in the sample. It will be incumbent on ERCOT to coordinate this type of change with the TSP and/or DSP, if appropriate.

18.2.10 Responsibilities for Sampling in Support of Load Profiling

18.2.10.1 ERCOT Sampling Responsibilities

ERCOT is responsible for the development and maintenance of Load Profiles used in the ERCOT market. ERCOT shall follow the Load Profiling and Load research rules and procedures as specified in the Public Utility Commission of Texas (PUCT) rules.

18.2.10.2 Transmission Service Provider and/or Distribution Service Provider Sampling Responsibilities

(1) The TSP's and/or DSP's Load research data are critical for Load Profile development by ERCOT. TSPs and/or DSPs, other than Non-Opt-In Entities (NOIE), shall provide available Load research data when requested by ERCOT.

(2) The TSPs and/or DSPs, other than NOIEs, shall provide ERCOT at least one year's notice of any significant change in the status of the TSP's and/or DSPs' Load research programs.

(3) TSPs and/or DSPs shall address the appropriate TAC subcommittee as a forum for their input in the development and refinement of Load Profiles.

(4) TSPs and/or DSPs shall follow the rules and procedures as specified in PUCT rules.

(5) ERCOT may request from TSPs and/or DSPs, and such TSPs and/or DSPs shall provide, the most current Load research data reasonably available to aid in the development or

refinement of Load Profile Models, subject to Section 18.2.8, Adjustments and Changes to Load Profile Development.

18.3 Posting

ERCOT will make available to Market Participants the following information in a timely manner, subject to confidentiality agreements, proprietary arrangements, and Public Utility Commission of Texas (PUCT) rules and regulations.

18.3.1 Methodology Information

A complete description of all supporting models, documentation and data used in preparation of Load Profiles will be made available on the Market Information System (MIS) Public Area, including:

(a) The historic Load data used to create the Load Profiles;

(b) Average interval accuracy of each Load Profiling model;

(c) Weather information;

(d) Sunrise/sunset information;

(e) Updates of Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) Load research data as it becomes available to ERCOT; and

(f) Any other data used for Load Profile development.

18.3.2 Load Profiling Models

ERCOT will make available the models used to produce the forecast and backcast profiles for the Settlement process. The Load Profile Models shall be accessible via the MIS Public Area in a downloadable format.

18.3.3 Load Profiles

(1) ERCOT will publish Load Profile data from the profile creation process, in accordance with Section 18.2.6, Daily Profile Creation Process, to the MIS and through the common application programming interface. Load Profile data will be made available to Market Participants for a period of two years.

(2) ERCOT will post to the MIS Public Area by 1000 Central Prevailing Time (CPT) each Business Day, forecasted Load Profiles for the three following days for each Load Profile Type and Weather Zone. Backcast profiles for each Load Profile Type and Weather

Zone will be available by 1000 CPT of the second Business Day following the backcast day. No data will be provided that will allow identification of individual Customers.

18.4 Assignment of Load Profile ID

Each Electric Service Identifier (ESI ID) is required to be associated with an appropriate Load Profile ID. This Section details the process of assigning a Load Profile ID to each ESI ID.

18.4.1 Development of Load Profile ID Assignment Table

ERCOT shall develop a cross-reference table of all Load Profile ID used in the ERCOT market. The table shall clearly state class relationship to Load Profile Type. This information shall be made accessible on the Market Information System (MIS) Public Area to all Market Participants. The cross-reference information shall be compiled and expressed in clear, unambiguous language, and in a manner that will minimize Load Profile ID assignment disputes.

18.4.2 Load Profile ID Assignment

(1) ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee shall review the Load Profile ID assignment process on an annual basis, make recommendations for enhancements, and evaluate the integration of the validation and assignment processes.

(2) Any Market Participant may request temporary changes to the yearly process for assigning and validating Load Profile IDs to address unusual circumstances. Such requests shall be submitted to the appropriate TAC subcommittee. If the request is approved by the TAC subcommittee, it shall then be submitted to the TAC. Such requests, if approved by the TAC, shall be in effect only for the requested year.

(3) Should there be any change in Load Profile ID assignment to any ESI ID, it will be the responsibility of the Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP) to submit those changes to ERCOT.

18.4.3 Validation of Load Profile Type and Weather Zone Assignments

In this Section validation shall mean performing checks to ensure correct assignment of Load Profile Types and Weather Zones to ESI IDs.

18.4.3.1 Validation Tests

(1) Validation tests of Load Profile Type and Weather Zone assignments, at a minimum, will occur at the following times:

(a) Initial Load Profile ID assignment;

(b) When a change is made in the Load Profile Type or Weather Zone assignment; and

(c) At least one time per year.

(2) ERCOT may utilize a sampling method for Load Profile Type assignment validation and when a change is made in the Load Profile ID assignment.

(3) ERCOT shall validate the assignment of the Weather Zone component of the Load Profile ID for all ESI IDs.

(4) ERCOT shall perform validation tests of the initial Load Profile Type and Weather Zone assignments of each TSP and/or DSP. Samples of assignments from the Residential and Business Profile Groups will be randomly drawn from each TSP's and/or DSP's population of profiled ESI IDs. If the assignment validation failure rate for any of these samples exceeds parameters specified in the Load Profiling Guide, ERCOT may request an audit of the corresponding TSP's and/or DSP's Load Profile ID assignment processes and systems at the expense of the TSP and/or DSP. ERCOT may require TSPs and/or DSPs that fail sample Load Profile Type or Weather Zone assignment validations and/or audits to resubmit Load Profile ID assignments for all ESI IDs in their service territory.

(5) Details of all validation tests will be specified in the Load Profiling Guide. Competitive Retailers (CR) may dispute a Load Profile ID assignment through the ERCOT Settlement dispute process, as described in Section 9.14, Settlement and Billing Dispute Process, in conjunction with the Load Profiling Guide.

(6) TSPs and/or DSPs shall change the assignment of a Load Profile ID based on a dispute outcome finding in favor of a CR. If required to change an assignment, TSPs and/or DSPs must correct the assignment in their system and the ERCOT Customer registration system within three Business Days.

18.4.3.2 Correction Procedure

(1) TSPs and/or DSPs are responsible for investigating each ESI ID identified by ERCOT as having a potentially incorrect Load Profile ID assignment. Each TSP and/or DSP shall work closely and promptly with ERCOT during the correction procedure, which is detailed in the Load Profiling Guide.

(2) Market Participants may dispute an assignment through the ERCOT Settlement dispute process, described in Section 9.14.

18.4.4 Assignment of Weather Zones to Electric Service Identifiers

(1) TSPs and /or DSPs will assign each ESI ID to a Weather Zone, based on service address ZIP code.

(2) ERCOT will post to the MIS Public Area a mapping of a Weather Zone to appropriate Customer registration element used in assigning Weather Zones.

18.5 Additional Responsibilities

This Section addresses responsibilities for Load Profiling not specified in other sections of the Protocols.

18.5.1 ERCOT Responsibilities

ERCOT will develop, administer, and maintain Load Profiles in accordance with these Protocols. Disputes related to the accuracy or appropriateness of Load Profiles shall be handled in accordance with Section 9.14, Settlement and Billing Dispute Process.

18.5.2 Transmission Service Provider and/or Distribution Service Provider Responsibilities

Transmission Service Providers (TSPs) and/or Distribution Service Providers (DSPs) shall use the appropriate Technical Advisory Committee (TAC) subcommittee as a forum for their input in the development and refinement of Load Profiles.

18.5.3 Competitive Retailer Responsibilities

(1) Competitive Retailers (CRs) shall use the appropriate TAC subcommittee as a forum for their input in the development and refinement of Load Profiles.

(2) CRs shall be responsible for reviewing any assignment of Load Profiles to Electric Service Identifiers (ESI IDs) they represent.

18.6 Installation and Use of Interval Data Recorders

18.6.1 Interval Data Recorder Installation and Use in Settlement

(1) Interval Data Recorder (IDR) Mandatory Installation Threshold: IDRs shall be installed and utilized for Settlement of Premises having either:

(a) A peak demand greater than 700 kW (or 700 kVA), or

(b) Service provided at transmission voltage (above 60 kV).

For the IDR installation process at Premises that meet the IDR Mandatory Installation Threshold identified above, refer to the Retail Market Guide Section 7.13.2.2, Mandatory IDR Installation Process.

(2) A Competitive Retailer (CR), upon a Customer's request or with a Customer's authorization, may have an IDR installed and used for Settlement purposes at any associated Premise outside the IDR Mandatory Installation Threshold. Except as stated in item (4) of this Section, IDRs in place or installed after September 1, 1999 shall be used for Settlement. Once an IDR is installed on a Premise and used for Settlement purposes, the given Premise shall continue to be settled with its interval data, except as stated in Section 18.6.6, Interval Data Recorder Optional Removal Threshold. If a Customer or CR requests installation of an IDR meter, the same Customer may not request removal of the IDR meter for a period of 12 consecutive months following such installation.

(3) All Non-Metered Loads such as street lighting, regardless of the aggregation level, shall not be required to install IDRs under the IDR Mandatory Installation Threshold. These Loads shall be settled using Load Profiles.

(4) For Premises not subject to the IDR Mandatory Installation Threshold in item (1) of this Section:

(a) IDRs installed at the request of ERCOT, a Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP), a Municipally Owned Utility (MOU), or an Electric Cooperative (EC) for Load research, rate/tariff design calculation, coincident demand calculation, or Load Profiling purposes shall be exempt from the requirement to use an IDR for Settlement purposes; or

(b) IDRs previously used specifically for separating Non-Opt-In Entity (NOIE) Load from competitive Load shall be exempt from the requirement to use an IDR for retail Customer settlement purposes, provided that the IDR meter has been removed within 120 consecutive days after the NOIE has fully implemented Customer Choice. IDR meters used for NOIE separation that do not meet the IDR Mandatory Installation Threshold shall not be used for retail Customer settlement purposes.

(5) For IDR installation procedures reference Section 10.2.2, TSP and DSP Metered Entities.

(6) TSPs and/or DSPs responsible for any Load transfer schemes between ERCOT and non-ERCOT Regions shall install IDR metering capable of measuring the Load served during the period the Load transfer is implemented.

18.6.2 Interval Data Recorder Administration Issues

ERCOT shall produce a report informing the appropriate Market Participants of profiled Premises that have become subject to the provisions of item (1) of Section 18.6.1, Interval Data Recorder Installation and Use in Settlement. ERCOT shall put in place a system to track Market Participants' timely adherence to this requirement. This report shall be posted to the Market Information System (MIS) Private Area.

18.6.3 Adherence to Interval Data Recorder Requirements

MOUs and ECs that opt-in to Customer Choice must install IDR meters at all Premises subject to the IDR Mandatory Installation Threshold for metering prior to the effective date of their participation in the testing and integration requirements of ERCOT Systems for Customer Choice.

18.6.4 Technical Requirements

(1) Regardless of data retrieval method, interval data shall be provided on a schedule that supports the requirements of final Settlement (typical monthly billing cycle).

(2) Interval data that is provided for Settlement shall be consistent with the ERCOT defined Settlement Interval.

18.6.5 Peak Demand Determination for Non-Interval Data Recorder Premises

(1) For the purpose of determining the peak Demand level for the IDR Mandatory Installation Threshold in Section 18.6.1, Interval Data Recorder Installation and Use in Settlement, the Demand will be determined in accordance with Public Utility Commission of Texas (PUCT) rulemaking or through a consensus process with ERCOT and Market Participants. In the absence of a clear definition of peak Demand in the PUCT rulemaking, the following application shall be used in determining the peak Demand level for IDR Mandatory Installation Threshold in Section 18.6.1.

(2) A Premise (Electric Service Identifier (ESI ID)) has a peak Demand greater than the applicable level in Section 18.6.1, above, when measured in any two billing months of the most recent 12 month period. CRs may dispute an IDR assignment through the ERCOT Settlement dispute process, described in Section 9.14, Settlement and Billing Dispute Process.

(3) ERCOT shall be responsible for receiving and storing Demand information necessary for determining mandatory IDR installations.

18.6.6 Interval Data Recorder Optional Removal Threshold

(1) The CR, upon a Customer's request or with a Customer's authorization, may request, in accordance with PUCT rules and regulations, removal of an IDR at the Customer's Premise unless service to the Premise is provided at transmission voltage (above 60 kV). However, once the Customer's Demand at the Premise meets the IDR Mandatory Installation Threshold identified in item (1) of Section 18.6.1, Interval Data Recorder Installation and Use in Settlement, the IDR will no longer qualify for removal.

(2) The "IDR Optional Removal Threshold" for a Premise is established as follows:

(a) For an existing Customer, where the Load at the Premise has not exceeded the IDR Optional Removal Threshold of 150 kW (kVA) during the most recent 12 consecutive months unless the existing Customer requested or authorized installation of an IDR pursuant to item (2) of Section 18.6.1 in which case the existing Customer may not request removal of the IDR for a period of 12 consecutive months following such installation; or

(b) For a new Customer move-in, where the request is communicated to the CR within 120 consecutive days of the move-in provided the new Customer's Demand at the Premise has remained below the IDR Mandatory Installation Threshold between the move-in date and the date the request is received, and that meter readings covering at least 45 consecutive days of usage at the Premise have been registered for the new Customer.

(3) Once an IDR has been removed at a Premise by request, an IDR may not be reinstalled at that Premise for a period of 12 consecutive months following such removal, unless a change in Customer(s) has taken place at that Premise during the 12 month period or unless the IDR Mandatory Installation Threshold pursuant to item (1) of Section 18.6.1 has been met. Removal or re-installation of an IDR is subject to applicable tariff charges.

18.7 Supplemental Load Profiling

ERCOT and the appropriate Technical Advisory Committee (TAC) subcommittee recognize the possible need to accommodate Load Profiling for programs or pricing schemes that encourage a Demand response to price in the retail market. Accordingly, Load Profiling methods other than adjusted static methodology are necessary.

18.7.1 Load Profiling of Time of Use Metered Electric Service Identifier

18.7.1.1 Overview

(1) A Time Of Use (TOU) meter is a programmable electronic device capable of measuring and recording electric energy in pre-specified time periods. For Load Profiling purposes

this definition does not include Interval Data Recorders (IDRs). For additional information regarding TOU, reference the Load Profiling Guide.

(2) The ERCOT Data Aggregation and Settlement systems must be able to accept and handle TOU meter data. The profiling of Premises participating in TOU programs requires TOU meter reads so that consumption can be distributed within the appropriate time periods.

18.7.1.2 Methodology for Load Profiling of Time Of Use

The selected technique for generating profiles for TOU Premises is described as follows:

(a) Each TOU Premise is assigned to a standard Load Profile Type.

(b) Upon agreement between the Competitive Retailer (CR) and Transmission Service Provider (TSP) and/or Distribution Service Provider (DSP), a Time of Use Schedule (TOUS) is submitted by the TSP and/or DSP to the ERCOT Data Aggregation System (DAS), which identifies the TOU period associated with each Settlement Interval. The number of TOU periods is determined by the number of periods for which the meter will capture kWh. These periods may include on-peak, off-peak, and shoulder periods. The DAS shall collect and maintain the attributes of the TOUS (e.g. start and stop time, day of the week, and season.).

(c) CRs shall communicate to TSPs and/or DSPs their Electric Service Identifiers (ESI IDs) associated with the proper TOUS.

(d) The TSP and/or DSP shall communicate all TOUSs to DAS so that proper TOUS identification for each Premise will occur in the ERCOT System.

(e) The ERCOT DAS shall use the standard Load Profile assigned to each TOU Premise and scale the energy for each TOU period in the Load Profile so that it is equal to the metered energy (kWh) for the TOU period.

(f) TOU Load Profiling will not use TOU Demand values.

18.7.1.3 Collection of Time Of Use Meter Data

TSPs and/or DSPs will be responsible for providing the meter reads necessary to support TOUS available in their service territory. The ERCOT DAS shall handle multiple TOU reads. These TOU reads may include on-peak, off-peak, and shoulder periods.

18.7.1.4 Availability of Time Of Use Schedules

The availability of TOUSs will be dependent on the following:

(a) For TSP and/or DSP service territories with TOU tariffs in effect prior to December 31, 2000, all CRs will be able to offer the TOUSs associated with those tariffs; and

(b) The implementation of any new or modified TOUS would be subject to the ERCOT and Texas Standard Electronic Transaction (TX SET) change control process.

18.7.1.5 Post Market Evaluation

Starting at the first completed Settlement cycle, ERCOT and the appropriate TAC subcommittee shall periodically review the selected profiling technique of TOU ESI IDs for accuracy, and validity. They may recommend enhancements, modifications, or a complete replacement of the technique.

18.7.2 Load Profiling of Electric Service Identifier Under Direct Load Control

This Section is reserved for future implementation of Direct Load Control (DLC).

18.7.3 Other Load Profiling

ERCOT, in coordination with the appropriate TAC subcommittee, may develop Load Profiles for particular Customer segments that require special Load Profiling techniques similar in nature to TOU and DLC programs.

ERCOT Nodal Protocols

Section 20: Alternative Dispute Resolution Procedure

Updated: July 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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20 ALTERNATIVE DISPUTE RESOLUTION PROCEDURE

20.1 Applicability

(1) Except as provided for in this Section, this Alternative Dispute Resolution (ADR) procedure shall apply to all disputes between ERCOT and one or more Market Participants or between two or more Market Participants relating to the application, implementation, and interpretation of, or compliance with these Protocols, any approved market guide, or related Agreements. ERCOT need not participate as a party or facilitator in the ADR procedure. If any party in the ADR procedure, however, requests that ERCOT facilitate resolution of a dispute, then ERCOT shall do so. A party shall submit a covered dispute to these ADR procedures as a condition precedent to any right of any legal action on the dispute. This ADR procedure is of general applicability.

(2) When an Agreement or a Protocol Section sets forth a specific dispute resolution procedure, the provisions of this Section shall apply only if the dispute remains unresolved after the other specific dispute resolution procedures have been exhausted.

(3) Except in the case of a disagreement involving a variance that has been filed through the ERCOT retail transaction issue resolution system or other ERCOT data discrepancy tracking method (i.e., the Data Extract Variance Process pursuant to the Retail Market Guide and MarkeTrak Users Guide), if the requested outcome of the ADR process involves the correction of Settlement data and resettlement by ERCOT pursuant to Section 9, Settlement and Billing, prior to requesting ADR, a Market Participant must comply with Section 9.14, Settlement and Billing Dispute Process. If the Market Participant does not comply with Section 9.14, then the Market Participant shall have waived the right to file a complaint regarding the Settlement Statement and ERCOT shall reject the ADR request without further action. Statement Recipients and Invoice Recipients are the only parties that may request the use of ADR where the requested relief would involve correction of Settlement data at ERCOT and resettlement by ERCOT pursuant to Section 9, Settlement and Billing, except where the disagreement involves a variance that has been filed through the Data Extract Variance Process.

(4) This Section shall apply to disagreements involving variances that are filed through a Data Extract Variance Process. The filing party must have previously complied with all requirements of a Data Extract Variance Process and submitted the initial variance by the deadline specified in the Data Extract Variance Process. A request for ADR relating to such a disagreement may seek the correction of the Settlement data and resettlement by ERCOT pursuant to Section 9. A party requesting ADR in connection with a Data Extract Variance Process need not have filed a Settlement and billing dispute pursuant to Section 9.14 in order to request and, if appropriate, receive resettlement through the ADR process.

(5) The procedures in this Section do not apply to disputes for which the sole remedy requires a change to the Protocols or related Agreements. The forum for resolution of

such disputes is the appropriate revision procedure(s) found in Section 21, Process for Protocol Revision.

(6) Nothing in this ADR procedure is intended to limit or restrict:

(a) The rights of any party to file a complaint with the Public Utility Commission of Texas (PUCT) or any other Governmental Authority, with respect to matters other than those specified in this Section;

(b) The right of ERCOT or any Market Participant to seek changes in rates or terms and conditions of services, or guidelines, criteria, Protocols, standards, policies, or procedures of ERCOT; or

(c) The right of a Market Participant or ERCOT to file a petition seeking direct relief from the PUCT or any other Governmental Authority without first utilizing this ADR procedure where an action by ERCOT or a Market Participant might inhibit the ability of the affected party to provide continuous and adequate electric service.

(7) The arbitration procedures set forth in Section 20.5, Arbitration Procedures, shall not apply to any claim that includes punitive damages as a part of the requested relief. Such a claim may be pursued in the appropriate forum without pursuing the requirements for arbitration procedures contained in Section 20.5.

(8) Except for the provisions of this Section, the ADR procedure may be modified by mutual agreement of the parties.

(9) Parties shall exercise good faith efforts to timely resolve disputes under this Section.

(10) Nothing here is intended to supersede any dispute resolution process mandated by applicable law or regulation.

(11) Unless the parties to the dispute agree otherwise or unless an applicable tariff or law provides otherwise, the ADR procedure does not apply to disputes between two or more Market Participants who are either:

(a) Parties to a bilateral agreement that relates to the subject matter of the dispute; or

(b) Governed by tariffs that relate to the subject matter of the dispute.

20.2 Initiation and Pursuit of ADR Process

20.2.1 Requirement for Written Request

(1) In order to initiate the Alternative Dispute Resolution (ADR) procedure, a Market Participant must submit a written request for ADR to the General Counsel of ERCOT. ERCOT shall provide Notice to all parties to the dispute within seven Business Days of

receipt of the ADR request and shall include the ERCOT ADR number in the Notice. For ADR proceedings that involve more than one Market Participant, each Market Participant shall provide the name and contact information of a contact point (Dispute Contact) within five Business Days of receipt of Notice from ERCOT. The written request shall include the following information:

(a) The name of the disputing Entity;

(b) The name and contact information of Dispute Contact for the disputing Entity;

(c) A description of the relief sought;

(d) A detailed description of the grounds for the relief and the basis of each claim which must, at a minimum, identify which Protocol Section(s), any other approved market guide, or related Agreement(s) that the application, implementation, interpretation of or compliance with is being challenged; and

(e) A list of all parties involved in the dispute.

(2) In addition to the foregoing requirements, for ADR proceedings involving Settlement disputes submitted pursuant to Section 9.14, Settlement and Billing Dispute Process, or for which the Market Participant seeks a monetary resolution, the Market Participant shall include the following additional information:

(a) Operating Day(s) involved in the dispute;

(b) Settlement dispute number; and,

(c) Amount in dispute (*i.e*. the additional compensation requested by the Market Participant).

20.2.2 Deadline for Initiating ADR Procedure

(1) For any ADR procedure invoked in connection with a Settlement and billing dispute submitted pursuant to Section 9.14, Settlement and Billing Disputes, the Market Participant submitting the dispute must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1, Requirement for Written Request) within 45 days of the date that ERCOT denied the Market Participant's Settlement and billing dispute. ERCOT shall post the dispute resolution date on the portion of the Market Information System (MIS) used for the processing of disputes.

(2) For any ADR procedure invoked in connection with a disagreement arising from a Data Extract Variance Process, the Market Participant submitting the ADR request must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1) no later than 45 days after issuance of the True-Up Statement for the applicable Operating Day.

(3) For any ADR procedure invoked in connection with any other matter that is not subject to this Section, the Market Participant submitting the dispute must provide Notice to the General Counsel of ERCOT (as set forth in Section 20.2.1) within six months of the date on which information giving rise to the ADR request became available to the Market Participant.

20.2.3 Failure to Pursue ADR Procedure

If the Market Participant that requested the ADR fails to diligently pursue its claim, ERCOT shall send a Notification to the Market Participant's Dispute Contact setting forth a deadline within which the Market Participant must respond in order to preserve its rights. The deadline shall be no less than 15 days from the date ERCOT sends the Notification. If the Market Participant fails to timely respond to two such Notifications by ERCOT, the Market Participant will be deemed to have waived its rights and the ADR shall be deemed closed. An affirmative statement in writing (including e-mail) that the Market Participant intends to pursue the ADR and a recommended course of action, including a proposed timeline, shall preserve the Market Participant's rights.

20.3 Informal Dispute Resolution

(1) Any dispute subject to Alternative Dispute Resolution (ADR) as described in this Section shall first be referred to a senior dispute representative of each of the parties to the dispute. The senior dispute representative shall be an individual with authority to resolve the dispute and administer the resolution (through delegation or otherwise). Such representatives shall make a good faith effort to resolve the dispute informally as promptly as practicable.

(2) If the senior dispute representatives cannot resolve the dispute by mutual agreement within 60 days of the date on which they take part in a meeting, then the dispute shall be referred to either:

(a) Mediation on the request of any party pursuant to Section 20.4, Mediation Procedures; or

(b) Arbitration on agreement of all parties pursuant to Section 20.5, Arbitration Procedures.

(3) When ERCOT is a party to the dispute and the parties waive the mediation and arbitration procedures by written agreement, the time periods for appeal of the ADR that are set forth in the applicable Public Utility Commission of Texas (PUCT) Substantive Rules shall apply from the date of the meeting between the senior dispute representatives.

20.4 Mediation Procedures

(1) The parties shall agree on a mediator who has no past or present official, financial, or personal conflict of interest with respect to the issues or parties in dispute, unless the interest is fully disclosed in writing to all participants in the dispute and all such participants waive in writing any objection to the conflict of interest. If the parties are unable to agree on a mediator within ten days of the request of any party to mediate, then the Commercial Mediation Rules of the American Arbitration Association (AAA) will be used to select the mediator.

(2) The mediator and senior dispute representatives of the parties shall commence mediation of the dispute within 15 days after the mediator's date of appointment. Communications regarding mediation shall be confidential and shall not be referred to or disclosed in any subsequent proceeding. The mediator shall aid the parties in reaching a mutually acceptable resolution of the dispute. The mediator shall have no authority to impose a resolution on the parties. If the parties have not resolved the dispute within 60 days of the first meeting with the mediator, such parties shall be deemed to be at impasse and the dispute may be submitted to arbitration on agreement of all parties. If such agreement regarding submission to arbitration cannot be reached, any of the parties may apply for relief to the Public Utility Commission of Texas (PUCT), or any other Governmental Authority.

20.5 Arbitration Procedures

20.5.1 Initiation of Arbitration

(1) If all the parties have agreed to arbitrate as provided in this Section, any party to the dispute may initiate arbitration by serving a Notice of arbitration, by first class mail certified with return receipt requested, courier service or facsimile, on the other party or parties to the dispute. The Notice of arbitration shall include:

(a) A statement of claims;

(b) A description of the relief sought;

(c) A brief summary of grounds for relief and basis of each claim;

(d) A list of all parties involved in the dispute; and

(e) A description of the good faith efforts made to resolve the dispute under the informal dispute resolution procedures under this Section.

(2) Even if ERCOT is not a party to the dispute, a copy of the Notice of arbitration shall be served on the General Counsel of ERCOT. Arbitration proceedings shall be deemed to commence on the date on which the Notice of arbitration is received by the non-filing parties.

(3) Each non-filing party shall file a response to the statement of the claim, and shall submit any counterclaims, within ten days of receiving the Notice of arbitration. The responses and any counterclaims shall be served on the General Counsel of ERCOT and all parties to the arbitration.

20.5.2 Selection of Arbitrators

(1) Within seven days after the response to the statement of the claim is filed, the parties to the arbitration shall meet to discuss the selection of an arbitrator.

(2) Arbitration shall, if possible, be conducted before a single neutral arbitrator appointed by the parties. If the parties fail to agree on a single arbitrator within seven days of their initial meeting, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. If there are more than two parties to the dispute, the parties filing the Notice of arbitration shall jointly select one arbitrator and the non-filing parties shall select another. The two arbitrators so chosen shall within seven days select a third arbitrator to chair the arbitration panel. If the two arbitrators are unable to agree on a third arbitrator to chair the panel, the two arbitrators shall be dismissed, and the parties shall each appoint a replacement, and the two replacement arbitrators shall within seven days select a third arbitrator to chair the panel.

(3) Arbitrators shall have no past or current official, financial, or personal conflict of interest with respect to the issues in dispute or parties, unless the interest is fully disclosed in writing to all participants and all participants waive in writing any objection to the conflict of interest.

(4) No party shall have any ex-parte communication with an arbitrator or proposed arbitrator subsequent to the time such person is proposed as an arbitrator and prior to completion of the arbitration process.

20.5.3 Intervention

(1) As soon as practicable after appointment of the arbitrator or the arbitration panel, the arbitrators shall submit to the General Counsel of ERCOT a summary of the dispute (which summary shall not include information claimed to be confidential, proprietary, or Customer-specific), which ERCOT shall post to the Market Information System (MIS) Secure Area. The summary by the arbitrators shall also specify a date for filing of interventions.

(2) An Entity seeking intervention must demonstrate that its rights or interests would be materially affected by the outcome of the arbitration and that it is subject to such outcome, and that it is subject to comparable facts and circumstances to those in dispute. Each party shall have an opportunity to respond to intervention requests. The arbitrators shall have full authority to grant, deny, or condition requests for intervention, including conferring party status on an Entity.

(3) Any Entity seeking to intervene in arbitration must agree to be bound by the Alternative Dispute Resolution (ADR) procedure of this Section and by the decision of the arbitrators, or of any tribunal to which the decision is appealed, to the same extent as the parties to the arbitration. Intervenors shall share in the costs of the arbitration to the same extent as the other parties to the arbitration.

20.5.4 Conduct of Arbitration

Except as otherwise provided herein, the arbitrators have full discretion over the conduct of hearings, briefing, scheduling, discovery, and other procedural matters. The arbitrators shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the American Arbitrators Association (AAA) Commercial Arbitration Rules and any applicable rules and regulations of the Public Utility Commission of Texas (PUCT) or any other tribunal having jurisdiction. In the event of a conflict between the AAA Commercial Arbitration Rules and rules and regulations of the PUCT or any other Governmental Authority, the rules and regulations of the PUCT or any other Governmental Authority having appropriate jurisdiction shall control. In the event of a conflict between the AAA Commercial Arbitration Rules and this ADR procedure, the procedures set forth in this Section shall control. In addition:

(a) The arbitrators shall allow reasonable opportunity for discovery.

(b) In conducting hearings, the arbitrators shall apply the rules of evidence (including claims of privilege) to the same extent as such rules would be applied by the PUCT or any other Governmental Authority.

(c) To the extent permitted by law, the arbitrators shall take appropriate actions to preserve the confidentiality of information claimed by a party to be confidential, proprietary or Customer-specific.

20.5.5 Arbitration Decisions

(1) The arbitrators shall be authorized only to interpret and apply the provisions of applicable statutory authority (including but not limited to the Public Utility Regulatory Act (PURA) or the Federal Power Act (FPA)), applicable rules, regulations and policies of regulatory authorities having jurisdiction (the PUCT or any other Governmental Authority), and these Protocols and related Agreements, and shall have no power to modify or change any of the foregoing.

(2) Within 120 days of appointment, the arbitrators shall render a final decision resolving the dispute. Such decision shall be based on the evidence in the record, the terms of the relevant Agreements and these Protocols, applicable statutes (including but not limited to PURA or the FPA), and applicable rules, regulations, and policies of the regulatory authority having jurisdiction (the PUCT or any other Governmental Authority). Such decision shall be in writing and shall provide the reasons therefore. The arbitrators may agree with the positions of one or more parties or may adopt a different resolution. The

arbitrator shall not have authority to grant punitive damages. If the decision is not rendered within 120 days of appointment, the arbitrators shall forfeit their fee and any of the parties may apply for relief to the PUCT or any other Governmental Authority having jurisdiction or to any court of competent jurisdiction.

(3) If the decision of the arbitrators is not timely appealed as provided in Section 20.5.6, Appeal of Arbitration Decision, the decision shall be final and binding on the parties. The parties shall take whatever action is required to comply with the decision, and judgment on the decision may be entered and enforced in any court having jurisdiction. Unless appealed, the final decision is binding precedent on the parties and intervenors with respect to the subject matter of the dispute, but is otherwise of no precedential force or effect.

20.5.6 Appeal of Arbitration Decision

(1) Any party to an arbitration under this Section may appeal an arbitration decision to the applicable authority (the PUCT or any Governmental Authority) by providing written notice to that effect to all other parties and intervenors in the arbitration, the arbitrators, ERCOT (if not otherwise served), and the applicable regulatory authority, no later than 30 days following the date the arbitration decision is issued.

(2) A party to arbitration under this Section may appeal the decision of the arbitrators only on the following grounds:

(a) An arbitrator failed to disclose a conflict of interest with one or more of the parties to the dispute, and the decision is substantially biased as a result of the undisclosed conflict;

(b) The decision is inconsistent with, or beyond the scope of, the relevant Agreements or these Protocols; or

(c) The decision is unjust, unreasonable, unduly discriminatory or preferential, or otherwise inconsistent with applicable statutes or with applicable rules, regulations and policies of the authority having jurisdiction (the PUCT or any other Governmental Authority).

(3) Any appeal of an arbitration decision shall be based solely on the record assembled by the arbitrators, unless all parties to the dispute agree in writing to reopen the record for a specified purpose. ERCOT and Market Participants intend that in any appeal, the applicable regulatory authority should accord substantial deference to the factual findings of the arbitrators.

(4) During the pendency of an appeal, the effect of the arbitration decision shall be stayed, unless the disputing parties otherwise agree.

(5) Agreement to these appellate review procedures shall be a precondition for intervention by an Entity other than ERCOT or a Market Participant in an arbitration proceeding under this Section.

20.6 Dispute Resolution Costs

(1) Each party shall be responsible for its own costs incurred during an Alternative Dispute Resolution (ADR) procedure and for a pro rata share of the cost of the mediator or arbitrators. The pro rata share will be based on the number of parties.

(2) The arbitrators may impose costs against an offending party if the arbitrators conclude that the party has abused the ADR procedure.

20.7 Requests for Data

(1) If, as part of the Alternative Dispute Resolution (ADR) procedure, a party requests documents or data from another party to the ADR, the responding party must provide within 15 days of the request either:

(a) The requested documents or data;

(b) An explanation of why the party believes the documents or data should not be produced (*e.g.* relevance); or,

(c) An explanation of why the information cannot be provided on that date and a reasonable date on which the documents or data will be produced.

(2) Additionally, if the ADR proceeds to mediation or arbitration, a party may request that arbitrator or mediator decide if documents or data are relevant to the ADR and, if it is relevant to the ADR, the document or data must be provided by the other party within a timeframe specified by the mediator or arbitrator.

(3) ERCOT and Market Participants will protect from public disclosure any and all Protected Information provided in response to the ADR procedure pursuant to a mutually agreeable confidentiality agreement.

(4) All information provided pursuant to this subsection may be provided by mail, facsimile, or other electronic communications.

20.8 Resolution of Disputes and Notification to Market Participants

(1) Upon resolution of an Alternative Dispute Resolution (ADR) claim, ERCOT and/or the Market Participants must enter into a written dispute resolution agreement disposing of the Market Participant’s claim.

(2) ERCOT shall send a Notification of the negotiated settlement amount and the manner in which the resulting overpayments or underpayments will be allocated to the appropriate Settlement Statement and Invoice Recipients, including the specific Settlement Statements and Invoices that will be affected. The Notification shall provide details including, but not limited to, the Operating Day, service type, total amount of the adjustment to the market and total adjustment to the Invoice Recipient.

(3) In the event a determination is made that there has been an error in ERCOT's processes, procedures, or systems that resulted in overpayments or underpayments to one or more Market Participants, the Chief Executive Officer (CEO) of ERCOT may negotiate a resolution to a dispute arising from such error in a manner that deviates from the normal application of the Protocols in order to settle the dispute under this ADR procedure with the approval of the ERCOT Board. These occurrences will be subject to the requirements of Section 9.2.6, Notice of Resettlement for the DAM, or Section 9.5.7, Notice of Resettlement for the Real-Time Market.

20.9 Settlement of Approved Alternative Dispute Resolution Claims

20.9.1 Adjustments Based on Alternative Dispute Resolution

(1) If Resettlement is possible to address an adjustment required by an Alternative Dispute Resolution (ADR) resolution, ERCOT shall issue a Resettlement Statement for the affected Operating Day(s) and shall adjust applicable timelines accordingly.

(2) If a resettlement is not practical or possible to address an adjustment required by an ADR resolution, ERCOT shall make the adjustments through a separate ADR Invoice that is produced outside of the normal Settlement system. The appropriate payments and charges, along with settlement quality information, shall be supplied to all Market Participants. Any dispute resolution amount greater than $5,000,000 shall be divided so that no one ADR Invoice has more than $5,000,000 in ADR adjustments and such ADR Invoices shall be issued at least 14 days apart from each other. Payments will be due on the date specified on the ADR Invoice. Any short and late payments will be handled pursuant to Section 9.4.4, Partial Payments, and 9.4.6, Late Fees, respectively.

20.9.2 Charges for Approved ADR Claim

The charges assigned to Market Participants to pay for an approved ADR claim will be settled on the same Settlement Statement as set forth in Section 20.9.1, Adjustments Based on Alternative Dispute Resolutions. ERCOT will assign the costs for the approved ADR claim according to the appropriate allocation for the market service in dispute as outlined in Section 6.9, Settlement for ERCOT-Provided Ancillary Services; Section 7.4, Congestion Management for Local Congestion; and, other Protocol Sections as appropriate. Charges that are necessary relating to other types of dispute resolution will be made in pursuant to the directives of the Protocols.

ERCOT Nodal Protocols

Section 22

Attachment A: Standard Form Market Participant Agreement

Updated: March 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

Standard Form Market Participant Agreement
Between
Participant
and
Electric Reliability Council of Texas, Inc.

This Market Participant Agreement ("Agreement"), effective as of the___________ day of _______________,___________ ("Effective Date"), is entered into by and between [Participant], a [State of Registration and Entity Type] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS:

A. As defined in the ERCOT Protocols, Participant is a (check all that apply):

☐ Load Serving Entity (LSE)

☐ Qualified Scheduling Entity (QSE)

☐ Transmission Service Provider (TSP)

☐ Distribution Service Provider (DSP)

☐ Congestion Revenue Right (CRR) Account Holder

☐ Resource Entity

☐ Renewable Energy Credit (REC) Account Holder

B. ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region; and

C. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the "Parties") hereby agree as follows:

Section 1. Notice.

All notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three (3) days after being deposited in the U.S. mail, first class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or overnight delivery service. Either Party may change its address for such notices by delivering to the other Party a written notice referring specifically to this Agreement. Notices required under the ERCOT Protocols shall be in accordance with the applicable Section of the ERCOT Protocols.

If to ERCOT:

Electric Reliability Council of Texas, Inc.
Attn: Legal Department
7620 Metro Center Drive
Austin, Texas 78744-1654
Telephone: (512) 225-7000
Facsimile: (512) 225-7079

If to Participant:

[Participant Name]
[Contact Person/Dept.]
[Street Address]
[City, State Zip]
[Telephone]
[Facsimile]

Section 2. Definitions.

A. Unless herein defined, all definitions and acronyms found in the ERCOT Protocols shall be incorporated by reference into this Agreement.

B. "ERCOT Protocols" shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and settlement (including customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. For the purposes of determining responsibilities and rights at a given time, the ERCOT Protocols, as amended in accordance with the change procedure(s) described in the ERCOT Protocols, in effect at the time of the performance or non-performance of an action, shall govern with respect to that action.

Section 3. Term and Termination.

A. Term. The initial term ("Initial Term") of this Agreement shall commence on the Effective Date and continue until thelast day of the month which is twelve (12) months from the Effective Date. After the Initial Term, this Agreement shall automatically renew for one-year terms (a "Renewal Term") unless the standard form of this Agreement contained in the ERCOT Protocols has been modified by a change to the ERCOT Protocols. If the standard form of this Agreement has been so modified, then this Agreement will terminate upon the effective date of the replacement agreement This Agreement may also be terminated during the Initial Term or the then-current Renewal Term in accordance with this Agreement.

B. Termination by Participant. Participant may, at its option, terminate this Agreement:

(1) immediately upon the failure of ERCOT to continue to be certified by the PUCT as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151;

(2) if the "REC Account Holder" box is checked in Section A. of the *Recitals* section of this Agreement, Participant may, at its option, terminate this Agreement immediately if the PUCT ceases to certify ERCOT as the entity approved by the PUCT ("Program Administrator") for carrying out the administrative responsibilities related to the Renewable Energy Credit Program as set forth in PUC Substantive Rule 25.173(g) without the immediate certification of another Program Administrator under PURA §39.151; or

(3) for any other reason at any time upon thirty days written notice to ERCOT.

C. Effect of Termination and Survival of Terms. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.

Section 4. Representations, Warranties, and Covenants.

A. Participant represents, warrants, and covenants that:

(1) Participant is duly organized, validly existing and in good standing under the laws of the jurisdiction under which it is organized and is authorized to do business in Texas;

(2) Participant has full power and authority to enter into this Agreement and perform all obligations, representations, warranties and covenants under this Agreement;

(3) Participant’s past, present and future agreements or Participant's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which Participant is a party or by which its assets or properties are bound do not materially affect performance of Participant's obligations under this Agreement;

(4) Market Participant’s execution, delivery and performance of this Agreement by Participant have been duly authorized by all requisite action of its governing body;

(5) Except as set out in an exhibit (if any) to this Agreement, ERCOT has not, within the twenty-four (24) months preceding the Effective Date, terminated for Default any Prior Agreement with Participant, any company of which Participant is a successor in interest, or any Affiliate of Participant;

(6) If any Defaults are disclosed on any such exhibit mentioned in subsection 4.A(5), either (a) ERCOT has been paid, before execution of this Agreement, all sums due to it in relation to such Prior Agreement, or (b) ERCOT, in its reasonable judgment, has determined that this Agreement is necessary for system reliability and Participant has made alternate arrangements satisfactory to ERCOT for the resolution of the Default under the Prior Agreement;

(7) Participant has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(8) Participant is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(9) Participant is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt;

(10) Participant acknowledges that it has received and is familiar with the ERCOT Protocols; and

(11) Participant acknowledges and affirms that the foregoing representations, warranties and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, “materially affecting performance” means resulting in a materially adverse effect on Participant's performance of its obligations under this Agreement.

B. <u>ERCOT represents, warrants and covenants that:</u>

(1) ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;

(2) ERCOT is duly organized, validly existing and in good standing under the laws of Texas, and is authorized to do business in Texas;

(3) ERCOT has full power and authority to enter into this Agreement and perform all of ERCOT's obligations, representations, warranties and covenants under this Agreement;

(4) ERCOT's past, present and future agreements or ERCOT's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which ERCOT is a party or by which its assets or properties are bound do not materially affect performance of ERCOT's obligations under this Agreement;

(5) The execution, delivery and performance of this Agreement by ERCOT have been duly authorized by all requisite action of its governing body;

(6) ERCOT has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(7) ERCOT is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(8) ERCOT is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt; and

(9) ERCOT acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the term of this Agreement. For purposes of this Section, "materially affecting performance" means resulting in a materially adverse effect on ERCOT's performance of its obligations under this Agreement.

Section 5. Participant Obligations.

A. Participant shall comply with, and be bound by, all ERCOT Protocols.

B. Participant shall not take any action, without first providing written notice to ERCOT and reasonable time for ERCOT and Market Participants to respond, that would cause a Market Participant within the ERCOT Region that is not a "public utility" under the Federal Power Act or ERCOT itself to become a "public utility" under the Federal Power

Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission.

Section 6. ERCOT Obligations.

A. ERCOT shall comply with, and be bound by, all ERCOT Protocols.

B. ERCOT shall not take any action, without first providing written notice to Participant and reasonable time for Participant and other Market Participants to respond, that would cause Participant, if Participant is not a "public utility" under the Federal Power Act, or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission. If ERCOT receives any notice similar to that described in Section 5.B. from any Market Participant, ERCOT shall provide notice of same to Participant.

Section 7. Payment.

For the transfer of any funds under this Agreement directly between ERCOT and Participant and pursuant to the Settlement procedures for Ancillary Services described in the ERCOT Protocols, the following shall apply:

A. Participant appoints ERCOT to act as its agent with respect to such funds transferred and authorizes ERCOT to exercise such powers and perform such duties as described in this Agreement or the ERCOT Protocols, together with such powers or duties as are reasonably incidental thereto.

B. ERCOT shall not have any duties, responsibilities to, or fiduciary relationship with Participant and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement except as expressly set forth herein or in the ERCOT Protocols.

Section 8. Default.

A. Event of Default.

(1) Failure to make payment or transfer funds, provide collateral or designate/maintain an association with a QSE (if required by the ERCOT Protocols) as provided in the ERCOT Protocols shall constitute a material breach and shall constitute an event of default ("Default") unless cured within two (2) Business Days after the non-breaching Party delivers to the breaching Party written notice of the breach. Provided further that if such a material breach, regardless of whether the breaching Party cures the breach within the allotted time after notice of the material breach, occurs more than three (3) times in a twelve-month period, the fourth such breach shall constitute a Default by the breaching Party.

(2) For any material breach other than a material breach described in Section 8(A)(1) the occurrence and continuation of any of the following events shall constitute an event of Default by Participant:

(a) Except as excused under subsection (4) or (5) below, a material breach, other than a material breach described in Section 8(A)(1), of this Agreement by Participant, including any material failure by Participant to comply with the ERCOT Protocols, unless cured within fourteen (14) Business Days after delivery by ERCOT of written notice of the material breach to Participant. Participant must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by ERCOT of written notice of such material breach by Participant and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within twelve-month period, the fourth such breach shall constitute a Default.

(b) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within 90 days thereafter.

(3) Except as excused under subsection (4) or (5) below, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a failure to make payment or transfer funds, shall constitute a Default by ERCOT unless cured within fourteen (14) Business Days after delivery by Participant of written notice of the material breach to ERCOT. ERCOT must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by Participant of written notice of such material breach by ERCOT and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a twelve-month period, the fourth such breach shall constitute a Default.

(4) For any material breach other than a failure to make payment or transfer funds, the breach shall not result in a Default if the breach cannot reasonably be cured within fourteen (14) calendar days, prompt written notice is provided by the breaching Party to the other Party, and the breaching Party began work or other efforts to cure the breach within three (3) Business Days after delivery of the notice to the breaching Party and prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(5) If, due to a Force Majeure Event, a Party is in breach with respect to any obligation hereunder, such breach shall not result in a Default by that Party.

B. <u>Remedies for Default.</u>

(1) ERCOT's Remedies for Default. In the event of a Default by Participant, ERCOT may pursue any remedies ERCOT has under this Agreement, at law, or in equity, subject to the provisions of Section 10: Dispute Resolution of this Agreement. In the event of a Default by Participant, if the ERCOT Protocols do not specify a remedy for a particular Default, ERCOT may, at its option, upon written notice to Participant, immediately terminate this Agreement, with termination to be effective upon the date of delivery of notice.

(2) Participant's Remedies for Default.

(a) Unless otherwise specified in this Agreement or in the ERCOT Protocols, and subject to the provisions of Section 10: Dispute Resolution of this Agreement in the event of a Default by ERCOT, Participant's remedies shall be limited to:

(i) Immediate termination of this Agreement upon written notice to ERCOT,

(ii) Monetary recovery in accordance with the Settlement procedures set forth in the ERCOT Protocols, and

(iii) Specific performance.

(b) However, in the event of a material breach by ERCOT of any of its representations, warranties or covenants, Participant's sole remedy shall be immediate termination of this Agreement upon written notice to ERCOT.

(c) If as a final result of any dispute resolution, ERCOT, as the settlement agent, is determined to have over-collected from a Market Participant(s), with the result that refunds are owed by Participant to ERCOT, as the settlement agent, such Market Participant(s) may request ERCOT to allow such Market Participant to proceed directly against Participant, in lieu of receiving full payment from ERCOT. In the event of such request, ERCOT, in its sole discretion, may agree to assign to such Market Participant ERCOT’s rights to seek refunds from Participant, and Participant shall be deemed to have consented to such assignment. This subsection (c) survives termination of this Agreement.

(3) A Default or breach of this Agreement by a Party shall not relieve either Party of the obligation to comply with the ERCOT Protocols.

C. Force Majeure.

(1) If, due to a Force Majeure Event, either Party is in breach of this Agreement with respect to any obligation hereunder, such Party shall take reasonable steps, consistent with Good Utility Practice, to remedy such breach. If either Party is unable to fulfill any obligation by reason of a Force Majeure Event, it shall give notice and the full particulars of the obligations affected by such Force Majeure

Event to the other Party in writing or by telephone (if followed by written notice) as soon as reasonably practicable, but not later than fourteen (14) calendar days, after such Party becomes aware of the event. A failure to give timely notice of the Force Majeure event shall constitute a waiver of the claim of Force Majeure Event. The Party experiencing the Force Majeure Event shall also provide notice, as soon as reasonably practicable, when the Force Majeure Event ends.

(2) Notwithstanding the foregoing, a Force Majeure Event does not relieve a Party affected by a Force Majeure Event of its obligation to make payments or of any consequences of non-performance pursuant to the ERCOT Protocols or under this Agreement, except that the excuse from Default provided by subsection 8.A(5) above is still effective.

D. Duty to Mitigate. Except as expressly provided otherwise herein, each Party shall use commercially reasonable efforts to mitigate any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Section 9. Limitation of Damages and Liability and Indemnification.

A. EXCEPT AS EXPRESSLY LIMITED IN THIS AGREEMENT OR THE ERCOT PROTOCOLS, ERCOT OR PARTICIPANT MAY SEEK FROM THE OTHER, THROUGH APPLICABLE DISPUTE RESOLUTION PROCEDURES SET FORTH IN THE ERCOT PROTOCOLS, ANY MONETARY DAMAGES OR OTHER REMEDY OTHERWISE ALLOWABLE UNDER TEXAS LAW, AS DAMAGES FOR DEFAULT OR BREACH OF THE OBLIGATIONS UNDER THIS AGREEMENT; PROVIDED, HOWEVER, THAT NEITHER PARTY IS LIABLE TO THE OTHER FOR ANY SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY THAT MAY OCCUR, IN WHOLE OR IN PART, AS A RESULT OF A DEFAULT UNDER THIS AGREEMENT, A TORT, OR ANY OTHER CAUSE, WHETHER OR NOT A PARTY HAD KNOWLEDGE OF THE CIRCUMSTANCES THAT RESULTED IN THE SPECIAL, INDIRECT, PUNITIVE OR CONSEQUENTIAL DAMAGES OR INJURY, OR COULD HAVE FORESEEN THAT SUCH DAMAGES OR INJURY WOULD OCCUR.

B. With respect to any dispute regarding a Default or breach by ERCOT of its obligations under this Agreement, ERCOT expressly waives any Limitation of Liability to which it may be entitled under the Charitable Immunity and Liability Act of 1987, Tex. Civ. Prac. & Rem. Code §84.006, or successor statute.

C. The Parties have expressly agreed that, other than subsections A and B of this Section, this Agreement shall not include any other limitations of liability or indemnification provisions, and that such issues shall be governed solely by applicable law, in a manner consistent with the Choice of Law and Venue subsection of this Agreement, regardless of any contrary provisions that may be included in or subsequently added to the ERCOT Protocols (outside of this Agreement).

D. The Independent Market Monitor (IMM), and its directors, officers, employees, and agents, shall not be liable to any person or Entity for any act or omission, other than an act or omission constituting gross negligence or intentional misconduct, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual, direct, indirect, or consequential damages of any kind resulting from or attributable to any such act or omission of the IMM, as long as such act or omission arose from or is related to matters within the scope of the IMM's authority arising under or relating to PURA §39.1515 and PUC SUBST. R. 25.365, Independent Market Monitor.

Section 10. Dispute Resolution.

A. In the event of a dispute, including a dispute regarding a Default, under this Agreement, Parties to this Agreement shall first attempt resolution of the dispute using the applicable dispute resolution procedures set forth in the ERCOT Protocols.

B. In the event of a dispute, including a dispute regarding a Default, under this Agreement, each Party shall bear its own costs and fees, including, but not limited to attorneys' fees, court costs, and its share of any mediation or arbitration fees.

Section 11. Miscellaneous.

A. Choice of Law and Venue. Notwithstanding anything to the contrary in this Agreement, this Agreement shall be deemed entered into and performable solely in Texas and, with the exception of matters governed exclusively by federal law, shall be governed by and construed and interpreted in accordance with the laws of the State of Texas that apply to contracts executed in and performed entirely within the State of Texas, without reference to any rules of conflict of laws. Neither Party waives primary jurisdiction as a defense; provided that any court suits regarding this Agreement shall be brought in a state or federal court located within Travis County, Texas, and the Parties hereby waive any defense of forum non-conveniens, except defenses under Tex. Civ. Prac. & Rem. Code §15.002(b).

B. Assignment.

(1) Notwithstanding anything herein to the contrary, a Party shall not assign or otherwise transfer all or any of its rights or obligations under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld or delayed, except that a Party may assign or transfer its rights and obligations under this Agreement without the prior written consent of the other Party (if neither the assigning Party or the assignee is then in Default of any Agreement with ERCOT):

(a) Where any such assignment or transfer is to an Affiliate of the Party; or

(b) Where any such assignment or transfer is to a successor to or transferee of the direct or indirect ownership or operation of all or part of the Party, or its facilities; or

(c) For collateral security purposes to aid in providing financing for itself, provided that the assigning Party will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by either Party pursuant to this Section will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). If requested by the Party making any such collateral assignment to a Financing Person, the other Party shall execute and deliver a consent to such assignment containing customary provisions, including representations as to corporate authorization, enforceability of this Agreement and absence of known Defaults, notice of material breach pursuant to Section 8(A), notice of Default, and an opportunity for the Financing Person to cure a material breach pursuant to Section 8(A) prior to it becoming a Default.

(2) An assigning Party shall provide prompt written notice of the assignment to the other Party. Any attempted assignment that violates this Section is void and ineffective. Any assignment under this Agreement shall not relieve either Party of its obligations under this Agreement, nor shall either Party's obligations be enlarged, in whole or in part, by reason thereof.

C. <u>No Third Party Beneficiary.</u> Except with respect to the rights of other Market Participants in Section 8.B. and the Financing Persons in Section 11.B., (i) nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, (ii) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (iii) this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to this Agreement or the services to be provided hereunder. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

D. <u>No Waiver.</u> Parties shall not be required to give notice to enforce strict adherence to all provisions of this Agreement. No breach or provision of this Agreement shall be deemed waived, modified or excused by a Party unless such waiver, modification or excuse is in writing and signed by an authorized officer of such Party. The failure by or delay of either Party in enforcing or exercising any of its rights under this Agreement shall (i) not be deemed a waiver, modification or excuse of such right or of any breach of the same or different provision of this Agreement, and (ii) not prevent a subsequent enforcement or exercise of such right. Each Party shall be entitled to enforce the other Party's covenants and promises contained herein, notwithstanding the existence of any claim or cause of action against the enforcing Party under this Agreement or otherwise.

E. Headings. Titles and headings of paragraphs and sections within this Agreement are provided merely for convenience and shall not be used or relied upon in construing this Agreement or the Parties' intentions with respect thereto.

F. Severability. In the event that any of the provisions, or portions or applications thereof, of this Agreement is finally held to be unenforceable or invalid by any court of competent jurisdiction, that determination shall not affect the enforceability or validity of the remaining portions of this Agreement, and this Agreement shall continue in full force and effect as if it had been executed without the invalid provision; provided, however, if either Party determines, in its sole discretion, that there is a material change in this Agreement by reason thereof, the Parties shall promptly enter into negotiations to replace the unenforceable or invalid provision with a valid and enforceable provision. If the Parties are not able to reach an agreement as the result of such negotiations within fourteen (14) days, either Party shall have the right to terminate this Agreement on three (3) days written notice.

G. Entire Agreement. Any Exhibits attached to this Agreement are incorporated into this Agreement by reference and made a part of this Agreement as if repeated verbatim in this Agreement. This Agreement represents the Parties' final and mutual understanding with respect to its subject matter. It replaces and supersedes any prior agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by any Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement. An agreement, statement, or promise not contained in this Agreement is not valid or binding.

H. Amendment. The standard form of this Agreement may only be modified through the procedure for modifying ERCOT Protocols described in the ERCOT Protocols. Any changes to the terms of the standard form of this Agreement shall not take effect until a new Agreement is executed between the Parties.

I. ERCOT's Right to Audit Participant. Participant shall keep detailed records for a period of three years of all activities under this Agreement giving rise to any information, statement, charge, payment or computation delivered to ERCOT under the ERCOT Protocols. Such records shall be retained and shall be available for audit or examination by ERCOT as hereinafter provided. ERCOT has the right during Business Hours and upon reasonable written notice and for reasonable cause to examine the records of Participant as necessary to verify the accuracy of any such information, statement, charge, payment or computation made under this Agreement. If any such examination reveals any inaccuracy in any such information, statement, charge, payment or computation, the necessary adjustments in such information, statement, charge, payment, computation, or procedures used in supporting its ongoing accuracy will be promptly made.

J. Participant's Right to Audit ERCOT. Participant's right to data and audit of ERCOT shall be as described in the ERCOT Protocols and shall not exceed the rights described in the ERCOT Protocols.

K. <u>Further Assurances.</u> Each Party agrees that during the term of this Agreement it will take such actions, provide such documents, do such things and provide such further assurances as may reasonably be requested by the other Party to permit performance of this Agreement.

L. <u>Conflicts.</u> This Agreement is subject to applicable federal, state, and local laws, ordinances, rules, regulations, orders of any Governmental Authority and tariffs. Nothing in this Agreement may be construed as a waiver of any right to question or contest any federal, state and local law, ordinance, rule, regulation, order of any Governmental Authority, or tariff. In the event of a conflict between this Agreement and an applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff, the applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff shall prevail, provided that Participant shall give notice to ERCOT of any such conflict affecting Participant. In the event of a conflict between the ERCOT Protocols and this Agreement, the provisions expressly set forth in this Agreement shall control.

M. <u>No Partnership.</u> This Agreement may not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party has any right, power, or authority to enter any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party except as provided in Section 7A.

N. <u>Construction.</u> In this Agreement, the following rules of construction apply, unless expressly provided otherwise or unless the context clearly requires otherwise:

(1) The singular includes the plural, and the plural includes the singular.

(2) The present tense includes the future tense, and the future tense includes the present tense.

(3) Words importing any gender include the other gender.

(4) The word "shall" denotes a duty.

(5) The word "must" denotes a condition precedent or subsequent.

(6) The word "may" denotes a privilege or discretionary power.

(7) The phrase "may not" denotes a prohibition.

(8) References to statutes, tariffs, regulations or ERCOT Protocols include all provisions consolidating, amending, or replacing the statutes, tariffs, regulations or ERCOT Protocols referred to.

(9) References to "writing" include printing, typing, lithography, and other means of reproducing words in a tangible visible form.

(10) The words “including,” “includes,” and “include” are deemed to be followed by the words “without limitation.”

(11) Any reference to a day, week, month or year is to a calendar day, week, month or year unless otherwise indicated.

(12) References to Articles, Sections (or subdivisions of Sections), Exhibits, annexes or schedules are to this Agreement, unless expressly stated otherwise.

(13) Unless expressly stated otherwise, references to agreements, ERCOT Protocols and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent the amendments and other modifications are not prohibited by this Agreement.

(14) References to persons or entities include their respective successors and permitted assigns and, for governmental entities, entities succeeding to their respective functions and capacities.

(15) References to time are to Central Prevailing Time.

O. Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.

Electric Reliability Council of Texas, Inc.:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Participant:

[USE OPTION 1 IF PARTICIPANT IS A CORPORATION

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

USE OPTION 2 IF PARTICIPANT IS A LIMITED PARTNERSHIP

By: ____,
as General Partner for [Participant]

Name:____

Title:____

Date:____

Market Participant Name:

____

Market Participant DUNS: ______________________________

ERCOT Nodal Protocols

Section 22

Attachment B: Standard Form Reliability Must-Run Agreement

Updated: March 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

Standard Form Reliability Must-Run Agreement
Between
(Participant)
and
Electric Reliability Council of Texas, Inc.

This Reliability Must-Run Agreement ("Agreement"), effective as of ____________ of ________________, ____________ ("Effective Date"), is entered into by and between [insert Participant's name], a [insert business entity type and state] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS:

A. Participant is a Resource Entity as defined in the ERCOT Protocols, and Participant intends to supply Reliability Must-Run Service;

B. ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region; and

C. The Parties enter into this Agreement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities under the ERCOT Protocols.

Agreements

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the "Parties") hereby agree as follows:

Section 1. Unit-Specific Terms.

A. Start Date: ________________, 20_____.

B. Stop Date: ________________, 20_____.

C. RMR Unit:___________________________.

D. Description of RMR Unit [*including location, name of Resource, etc.]:*

____

____, as described in more detail on Exhibit 1. Exhibit 1 should include any significant maintenance and operational information needed for ERCOT to comply with these Protocols. If Unit is a combined-cycle Generation Resource, indicate the Unit's operational capability for each power train as envisioned to supply RMR service as specified in the ERCOT Protocols in effect on the Effective Date.

F. RMR Unit Information

(1) RMR Capacity: _____ MW.

(2) Power factor lagging

(a) _____ P.F. (at generator main leads); and

(b) _____ P.F. (at high side of main power transformer)

(3) Power factor leading

(a) _____ P.F. (at generator main leads); and

(b) _____ P.F. (at high side of main power transformer)

(4) Target Availability

G. Delivery Point: ___________________________

H. Revenue Meter Location (Use Resource IDs): __________________________

I. Operational and Environmental Limitations (check and describe all that apply):

(1) Operational

☐ Maximum annual hours of operation: _________________

☐ Maximum annual MWh: ___________________________

☐ Maximum annual starts: ___________________________

☐ Other: ____

(2) Environmental

☐ Maximum annual NO_x emissions: ____________________

☐ Maximum annual SO_2 emissions: ____________________

☐ Other: ____

If applicable, upon ERCOT's request, Participant shall make reasonable efforts to secure additional credits or allowances to allow additional operation of the RMR Unit if ERCOT's planned use will exceed any of the Environmental Limitations set forth above. Participant shall provide ERCOT with advance notice of the cost of these credits prior to making the purchase.

The value of any additional credits acquired at ERCOT's request shall be considered Eligible Costs.

J. Inputs for Payments for RMR Unit:

(1) Estimated Start Up Fuel:_______________ MMBtu per start.

(a) Warm Start: ____

(b) Cold Start: _____

(2) Estimated Fuel Adder

(3) I/O Curve (MMBtu per MW per hour), attached as Exhibit 2.

(4) Estimated Standby Cost: $________ per hour.

(5) Incentive Factor Percentage: ______% of Eligible Costs.

K. Notice. All notices required to be given under this Agreement shall be in writing, and shall be deemed delivered three days after being deposited in the U.S. mail, first-class postage prepaid, registered (or certified) mail, return receipt requested, addressed to the other Party at the address specified in this Agreement or shall be deemed delivered on the day of receipt if sent in another manner requiring a signed receipt, such as courier delivery or Federal Express delivery. Either Party may change its address for such notices by delivering to the other Party a written notice referring specifically to this Agreement. Notices required under the ERCOT Protocols shall be in accordance with the applicable Section of the ERCOT Protocols.

If to ERCOT:

Electric Reliability Council of Texas, Inc.
7620 Metro Center Drive
Austin, Texas 78744-1654
Tel No. (512) 225-7000

Attn: ERCOT Legal Department

If to Participant:

[insert information]

Section 2. Definitions.

A. Unless herein defined, all definitions and acronyms found in the ERCOT Protocols shall be incorporated by reference into this Agreement.

B. “ERCOT Protocols” shall mean the document adopted by ERCOT, including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. For the purposes of determining prices, payments, and other economic rights of the Parties, the ERCOT Protocols in effect on the Effective Date govern this Agreement. For the purposes of determining all other responsibilities and rights at a given time, the ERCOT Protocols, as amended in accordance with the change procedure(s) described in the ERCOT Protocols, in effect at the time of the performance or non-performance of an action, shall govern with respect to that action.

Section 3. Term and Termination.

A. Term.

(1) This Agreement is effective beginning on the Effective Date.

(2) The “Term” of this Agreement begins at 0000 on the Start Date and ends at 2400 on the Stop Date. ERCOT, at its sole discretion, may terminate this Agreement before the end of the Term by giving 90 days’ advance written notice to the Participant.

(3) Any Term longer than one (1) year requires ERCOT Board approval.

B. Extension by ERCOT. ERCOT may, at its sole discretion, extend this Agreement for a period up to ninety (90) days, even if ERCOT has previously provided notice to Participant of future termination of the Agreement, by providing at least thirty (30) days advance written notice to Participant of the extension.

C. Termination by Participant. Participant may, at its option, immediately terminate this Agreement upon the failure of ERCOT to continue to be certified by the PUCT as the Independent Organization under PURA §39.151 without the immediate certification of another Independent Organization under PURA §39.151.

D. Termination by Mutual Agreement. This Agreement may be terminated upon written agreement of both parties at a time specified by such agreement; provided that Participant may still recover Eligible Costs (Standby Price) and Incentive Factor payments already accrued prior to termination pursuant to this section.

E. Effect of Termination and Survival of Terms. If this Agreement is terminated by a Party pursuant to the terms hereof, the rights and obligations of the Parties hereunder shall terminate, except that the rights and obligations of the Parties that have accrued under this Agreement prior to the date of termination shall survive.

Section 4. Representations, Warranties, and Covenants.

A. Participant represents, warrants, and covenants that:

(1) Participant is duly organized, validly existing, and in good standing under the laws of the jurisdiction under which it is organized, and is authorized to do business in Texas;

(2) Participant has full power and authority to enter into this Agreement and perform all of Participant's obligations, representations, warranties, and covenants under this Agreement;

(3) Participant's past, present, and future agreements or Participant's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which Participant is a party or by which its assets or properties are bound do not materially affect performance of Participant's obligations under this Agreement;

(4) The execution, delivery, and performance of this Agreement by Participant have been duly authorized by all requisite action of its governing body;

(5) Except as set out in an exhibit (if any) to this Agreement, ERCOT has not, within the 24 months preceding the Effective Date, terminated for Default any Prior Agreement with Participant, any company of which Participant is a successor in interest, or any Affiliate of Participant;

(6) If any Defaults are disclosed on any such exhibit mentioned in subsection 4.A(5), either (a) ERCOT has been paid, before execution of this Agreement, all sums due to it in relation to such Prior Agreement, or (b) ERCOT, in its reasonable judgment, has determined that this Agreement is necessary for system reliability, and Participant has made alternate arrangements satisfactory to ERCOT for the resolution of the Default under the Prior Agreement;

(7) Participant has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(8) Participant is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(9) Participant is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt;

(10) Participant acknowledges that it has received and is familiar with the ERCOT Protocols; and

(11) Participant acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the Term of this Agreement. For purposes of this Section, "materially affecting performance" means resulting in a materially adverse effect on Participant's performance of its obligations under this Agreement.

B. ERCOT represents, warrants, and covenants that:

(1) ERCOT is the Independent Organization certified under PURA §39.151 for the ERCOT Region;

(2) ERCOT is duly organized, validly existing, and in good standing under the laws of Texas, and is authorized to do business in Texas;

(3) ERCOT has full power and authority to enter into this Agreement and perform all of ERCOT's obligations, representations, warranties, and covenants under this Agreement;

(4) ERCOT's past, present, and future agreements or ERCOT's organizational charter or bylaws, if any, or any provision of any indenture, mortgage, lien, lease, agreement, order, judgment, or decree to which ERCOT is a party or by which its assets or properties are bound do not materially affect performance of ERCOT's obligations under this Agreement;

(5) The execution, delivery, and performance of this Agreement by ERCOT have been duly authorized by all requisite action of its governing body;

(6) ERCOT has obtained, or will obtain prior to beginning performance under this Agreement, all licenses, registrations, certifications, permits and other authorizations and has taken, or will take prior to beginning performance under this Agreement, all actions required by applicable laws or governmental regulations except licenses, registrations, certifications, permits or other authorizations that do not materially affect performance under this Agreement;

(7) ERCOT is not in violation of any laws, ordinances, or governmental rules, regulations or order of any Governmental Authority or arbitration board materially affecting performance of this Agreement and to which it is subject;

(8) ERCOT is not Bankrupt, does not contemplate becoming Bankrupt nor, to its knowledge, will become Bankrupt; and

(9) ERCOT acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the Term of this Agreement. For purposes of this Section, "materially affecting performance," means resulting in a materially adverse effect on ERCOT's performance of its obligations under this Agreement.

Section 5. Participant Obligations.

A. Participant shall comply with, and be bound by, all ERCOT Protocols as they pertain to provision of Reliability Must-Run Service by a Resource Entity.

B. Participant shall not take any action, without first providing written notice to ERCOT and reasonable time for ERCOT and Market Participants to respond, that would cause a Market Participant within the ERCOT Region that is not a "public utility" under the Federal Power Act or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission.

Section 6. ERCOT Obligations.

A. ERCOT shall comply with, and be bound by, all ERCOT Protocols.

B. ERCOT shall not take any action, without first providing written notice to Participant and reasonable time for Participant and other Market Participants to respond, that would cause Participant, if Participant is not a "public utility" under the Federal Power Act, or ERCOT itself to become a "public utility" under the Federal Power Act or become subject to the plenary jurisdiction of the Federal Energy Regulatory Commission. If ERCOT receives any notice similar to that described in Section 5.B from any Market Participant, ERCOT shall provide notice of same to Participant.

Section 7. Capacity Tests for RMR Units.

A. Capacity Tests.

(1) A "Capacity Test" is a one-hour performance test of the RMR Unit by Participant. The capacity as shown by a Capacity Test is called "Tested Capacity" and is determined by the applicable net meter readings during the Capacity Test.

(2) ERCOT may require that a Capacity Test be run at ERCOT's discretion at any time when the RMR Unit is on line, but ERCOT may not require more than four Capacity Tests in a contract Term. ERCOT must give Participant at least two (2) hours advance notice, after the RMR Unit is on line, of a Capacity Test required by ERCOT, unless Participant agrees to less than two (2) hours. Participant may perform as many Capacity Tests as it desires, but Participant may not perform a Capacity Test without the prior approval of ERCOT, which approval ERCOT may not unreasonably withhold or delay. The Parties will reasonably cooperate to coordinate a Capacity Test. ERCOT has the right to reasonable advance notice of, and to have personnel present during, a Capacity Test.

B. Test Report. ERCOT shall give the Capacity Test results in writing (the "Capacity Test Report") to Participant within twenty-four (24) hours after the test is run.

C. Effect of Test.

(1) A determination of Tested Capacity is effective as of the beginning of the hour in which the Capacity Test is started. For all hours in which Tested Capacity is less than the RMR Capacity specified in Section 1.F(1)(a) above, then the Incentive Factor Percentage may be reduced as specified in the ERCOT Protocols applicable to RMR Service in effect on the Effective Date.

Section 8. Operation.

A. RMR Unit Maintenance. Before the start of each contract Term, Participant shall furnish ERCOT with its proposed schedule for Planned Outages for inspection, repair, maintenance, and overhaul of the RMR Unit for the contract Term. Participant will promptly advise ERCOT of any later changes to the schedule. The specific times for Planned Outages of the RMR Unit must be approved or rejected by ERCOT within thirty (30) days after submission by a Participant. Requested outages may be rejected only if necessary to assure reliability of the ERCOT System. ERCOT shall, if requested by Participant, endeavor to accommodate changes to the schedule to the extent that reliability of the ERCOT System is not materially affected by those changes. In all cases, ERCOT must find a time for Participant to perform maintenance in a reasonable timeframe.

B. Planning Data.

(1) Participant shall timely report to ERCOT those items and conditions necessary for ERCOT's internal planning and compliance with ERCOT's guidelines in effect from time to time. The information supplied must include, without limitation, the following:

(a) Availability Plan for the Operating Day (transmitted to ERCOT 0600 of the Day Ahead);

(b) Revised Availability Plan reflecting changes in the Plan as soon as reasonably practical, but in no event later than 60 minutes after the event that caused the change; and

(c) Status of the RMR Unit with respect to Environmental Limitations listed in Section 1.I above, if any. If any of the specified Environmental Limitations will be exceeded by ERCOT's planned or actual use of the RMR Unit Participant shall provide ERCOT with as much advance written notice as is reasonably possible.

(2) ERCOT and Participant shall timely coordinate with each other on the status of the RMR Unit with respect to Operational Limitations.

C. Delivery.

(1) ERCOT shall notify Participant, through its QSE, of the hours and levels of generation, if any, that the RMR Unit is to operate. This information is called the "Delivery Plan." ERCOT may not notify Participant to operate at levels above those stated in the Availability Plan, and ERCOT may not notify Participant to operate the Unit in a manner that would violate the limitations on operation set out in Section 1 above.

(2) Participant shall produce and deliver electrical energy from the RMR Unit to the Delivery Point at the levels specified in the Delivery Plan.

(3) ERCOT may not dispatch the Unit if compliance with the dispatch would cause the Unit to exceed the Operational and Environmental Limitations, if any, set forth in Section 1.I above or at levels greater than are shown in the Availability Plan. Notwithstanding the foregoing, Participant retains the responsibility for operating the Unit under limits provided by applicable law.

(4) *The following section is only applicable if the RMR Unit is subject to Environmental Limitations identified in Section 1.I(2).* Participant may, upon reasonable advance written notice to ERCOT, shut down the RMR Unit for the remaining Term of this Agreement if (a) the shutdown is necessary in Participant's reasonable judgment to comply with Participant's legal obligation to stay within the Environmental Limitations, (b) ERCOT's use of the RMR Unit has caused the RMR Unit to exceed, or will immediately cause the RMR Unit to exceed, the Environmental Limitations specified herein for the entire remainder of the Term of the Agreement and (c)(*i*) Participant has been unsuccessful in its reasonable attempts procuring additional credits or allowances to allowed continued operation of the RMR Unit or (*ii*) ERCOT has not requested that Participant attempt to procure additional credits or allowances. Participant may, upon reasonable advance written notice to ERCOT, temporarily suspend operation of the RMR Unit at any time, and from time to time, if the refusal is necessary in Participant's reasonable judgment to comply with Participant's legal obligation to stay within the Environmental Limitations specified herein. For purposes of determining Actual Availability, the RMR Unit shall be considered to be available at full capacity in any hours in which the RMR Unit is unavailable because Participant has exercised its rights to shut down or suspend operation under this section.

<u>Section 9. Payment.</u>

A. For the transfer of any funds under this Agreement directly between ERCOT and Participant and pursuant to the Settlement procedures for Ancillary Service described in the ERCOT Protocols, the following shall apply:

(1) Participant appoints ERCOT to act as its agent with respect to such funds transferred and authorizes ERCOT to exercise such powers and perform such duties as described in this Agreement or the ERCOT Protocols, together with such powers or duties as are reasonably incidental thereto.–

(2) ERCOT shall not have any duties, responsibilities to, or fiduciary relationship with Participant and no implied covenants, functions, responsibilities, duties, obligations or liabilities shall be read into this Agreement except as expressly set forth herein or in the ERCOT Protocols.

B. <u>Payments for an RMR Unit.</u> ERCOT shall pay Participant for the RMR Service provided under this Agreement as specified in the ERCOT Protocols applicable to RMR Service, as those ERCOT Protocols are in effect on the Effective Date.

C. <u>Unexcused Misconduct Events.</u>

(1) For a RMR Unit, a "Misconduct Event" means any hour or hours during which Participant is requested to, but does not, deliver to ERCOT Energy at a level of at least 98% on each hour (on a kilowatt-hour/hour basis) of the level shown in the Availability Plan.

(2) For a Synchronous Condenser Unit, a "Misconduct Event" means any hour or hours during which Participant is requested to, but does not, synchronize the Unit to the ERCOT Transmission Grid during any hour in which the Unit is shown in the Availability Plan.

(3) Each day that a Misconduct Event continues after Participant receives written notice from ERCOT of the Misconduct Event is a separate Misconduct Event. Misconduct Event is measured on a daily basis.

(4) Participant is excused from the Misconduct Event payment reduction arising from any Misconduct Event that is (a) not due to intentionally incomplete, inaccurate, or dishonest reporting to ERCOT by Participant of the availability of the Unit, or (b) caused by a failure of the ERCOT Transmission Grid.

(5) If a Misconduct Event is not excused, then to reflect this lower-than-expected quality of firmness, ERCOT's payments to Participant are reduced as specified in the ERCOT Protocols in effect on the Effective Date.

(6) ERCOT shall inform Participant in writing of its determination if a Misconduct Event is unexcused.

(7) ERCOT may offset any amounts due by Participant to ERCOT under this Section 9.D against any amounts due by ERCOT to Participant under this Agreement.

Section 10. Default.

A. Event of Default.

(1) Failure to make payment or transfer funds as provided in the ERCOT Protocols shall constitute a material breach and shall constitute an event of default ("Default") unless cured within three (3) Business Days after delivery by the non-breaching Party of written notice of the failure to the breaching Party. Provided further that if such a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a rolling 12-month period, the fourth such breach shall constitute a Default by the breaching Party.

(2) For any material breach other than a failure to make payment or transfer funds, the occurrence and continuation of any of the following events shall constitute an event of Default by Participant:

(a) Except as excused under subsection (4) or (5) below, a material breach, other than a failure to make payment or transfer funds, of this Agreement by Participant, including any material failure by Participant to comply with the ERCOT Protocols, unless cured within fourteen (14) Business Days after delivery by ERCOT of written notice of the material breach to Participant. Participant must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by ERCOT of written notice of such material breach by Participant and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a rolling 12month period, the fourth such breach shall constitute a Default.

(b) Participant becomes Bankrupt, except for the filing of a petition in involuntary bankruptcy, or similar involuntary proceedings, that is dismissed within 90 days thereafter.

(c) The RMR Unit's operation is abandoned without intent to return it to operation during the Term;

(d) At any time, the Actual Availability is equal to or less than 50%; or

(e) Three or more unexcused Misconduct Events occur during a contract Term.

(3) Except as excused under subsection (4) or (5) below, a material breach of this Agreement by ERCOT, including any material failure by ERCOT to comply with the ERCOT Protocols, other than a failure to make payment or transfer funds, shall constitute a Default by ERCOT unless cured within fourteen (14) Business Days after delivery by Participant of written notice of the material breach to ERCOT. ERCOT must begin work or other efforts within three (3) Business Days to cure such material breach after delivery by Participant of written notice of such material breach by ERCOT and must prosecute such work or other efforts with reasonable diligence until the breach is cured. Provided further that if a material breach, regardless of whether such breach is cured within the allotted time after notice of the material breach, occurs more than three (3) times within a rolling 12 month period, the fourth such breach shall constitute a Default.

(4) For any material breach other than a failure to make payment or transfer funds, the breach shall not result in a Default if the breach cannot reasonably be cured within 14 calendar days, prompt written notice is provided by the breaching Party to the other Party, and the breaching Party began work or other efforts to cure the breach within 3 Business Days after delivery of the notice to the breaching Party and prosecutes the curative work or efforts with reasonable diligence until the curative work or efforts are completed.

(5) If, due to a Force Majeure Event, a Party is in breach with respect to any obligation hereunder, such breach shall not result in a Default by that Party.

B. Remedies for Default.

(1) ERCOT's Remedies for Default. In the event of a Default by Participant, ERCOT may pursue any remedies ERCOT has under this Agreement, at law, or in equity, subject to the provisions of Section 12: Dispute Resolution of this Agreement. In the event of a Default by Participant, if the ERCOT Protocols do not specify a remedy for a particular Default, ERCOT may, at its option, upon written notice to Participant, immediately terminate this Agreement, with termination to be effective upon the date of delivery of notice.

(2) Participant’s Remedies for Default.

(a) Unless otherwise specified in this Agreement or in the ERCOT Protocols, and subject to the provisions of Section 12: Dispute Resolution of this Agreement, in the event of a Default by ERCOT, Participant’s remedies shall be limited to:

(i) Immediate termination of this Agreement upon written notice to ERCOT,

(ii) Monetary recovery in accordance with the Settlement procedures set forth in the ERCOT Protocols, and

(iii) Specific performance.

(b) However, in the event of a material breach by ERCOT of any of its representations, warranties or covenants, described in Section 4.B, Participant’s sole remedy shall be immediate termination of this Agreement upon written notice to ERCOT.

(c) If as a final result of any dispute resolution ERCOT, as the settlement agent, is determined to have over-collected from a Market Participant(s), with the result that refunds are owed by Participant to ERCOT, as the settlement agent, such Market Participant(s) may request ERCOT to allow such Market Participant to proceed directly against Participant, in lieu of receiving full payment from ERCOT. In the event of such request, ERCOT, in its sole discretion, may agree to assign to such Market Participant ERCOT’s rights to seek refunds from Participant, and Participant shall be deemed to have consented to such assignment. This subsection (c) survives termination of this Agreement.

(3) A Default or breach of this Agreement by a Party shall not relieve either Party of the obligation to comply with the ERCOT Protocols.

C. Force Majeure.

(1) If, due to a Force Majeure Event, either Party is in breach of this Agreement with respect to any obligation hereunder, such Party shall take reasonable steps, consistent with Good Utility Practice, to remedy such breach. If either Party is unable to fulfill any obligation by reason of a Force Majeure Event, it shall give notice and the full particulars of the obligations affected by such Force Majeure Event to the other Party in writing or by telephone (if followed by written notice) as soon as reasonably practicable, but not later than fourteen (14) calendar days, after such Party becomes aware of the event. A failure to give timely notice of the Force Majeure Event shall constitute a waiver of the claim of Force Majeure Event. The Party experiencing the Force Majeure Event shall also provide notice, as soon as reasonably practicable, when the Force Majeure Event ends.

(2) Notwithstanding the foregoing, a Force Majeure Event does not relieve a Party affected by a Force Majeure Event of its obligation to make payments or of any consequences of non-performance pursuant to the ERCOT Protocols or under

this Agreement, except that the excuse from Default provided by subsection 10.A(5) is still effective.

D. Duty to Mitigate. Except as expressly provided otherwise herein, each Party shall use commercially reasonable efforts to mitigate any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Section 11. Limitation of Damages and Liability and Indemnification.

A. EXCEPT AS EXPRESSLY LIMITED IN THIS AGREEMENT OR THE ERCOT PROTOCOLS, ERCOT OR PARTICIPANT MAY SEEK FROM THE OTHER, THROUGH APPLICABLE DISPUTE RESOLUTION PROCEDURES SET FORTH IN THE ERCOT PROTOCOLS, ANY MONETARY DAMAGES OR OTHER REMEDY OTHERWISE ALLOWABLE UNDER TEXAS LAW, AS DAMAGES FOR DEFAULT OR BREACH OF THE OBLIGATIONS UNDER THIS AGREEMENT; PROVIDED, HOWEVER, THAT NEITHER PARTY IS LIABLE TO THE OTHER FOR ANY SPECIAL, INDIRECT, PUNITIVE, OR CONSEQUENTIAL DAMAGES OR INJURY THAT MAY OCCUR, IN WHOLE OR IN PART, AS A RESULT OF A DEFAULT UNDER THIS AGREEMENT, A TORT, OR ANY OTHER CAUSE, WHETHER OR NOT A PARTY HAD KNOWLEDGE OF THE CIRCUMSTANCES THAT RESULTED IN THE SPECIAL, INDIRECT, PUNITIVE, OR CONSEQUENTIAL DAMAGES OR INJURY, OR COULD HAVE FORESEEN THAT SUCH DAMAGES OR INJURY WOULD OCCUR.

B. With respect to any dispute regarding a Default or breach by ERCOT of its obligations under this Agreement, ERCOT expressly waives any Limitation of Liability to which it may be entitled under the Charitable Immunity and Liability Act of 1987, Tex. Civ. Prac. & Rem. Code §84.006, or successor statute.

C. The Parties have expressly agreed that, other than subsections A and B of this Section, this Agreement shall not include any other limitations of liability or indemnification provisions, and that such issues shall be governed solely by applicable law, in a manner consistent with the Choice of Law and Venue subsection of this Agreement, regardless of any contrary provisions that may be included in or subsequently added to the ERCOT Protocols (outside of this Agreement).

Section 12. Dispute Resolution.

A. In the event of a dispute, including a dispute regarding a Default, under this Agreement, Parties to this Agreement shall first attempt resolution of the dispute using the applicable dispute resolution procedures set forth in the ERCOT Protocols.

B. In the event of a dispute, including a dispute regarding a Default, under this Agreement, each Party shall bear its own costs and fees, including, but not limited to attorneys' fees, court costs, and its share of any mediation or arbitration fees.

Section 13. Miscellaneous.

A. Choice of Law and Venue. Notwithstanding anything to the contrary in this Agreement, this Agreement shall be deemed entered into and performable solely in Texas and, with the exception of matters governed exclusively by federal law, shall be governed by and construed and interpreted in accordance with the laws of the State of Texas that apply to contracts executed in and performed entirely within the State of Texas, without reference to any rules of conflict of laws. Neither Party waives primary jurisdiction as a defense; provided that any court suits regarding this Agreement shall be brought in a state or federal court located within Travis County, Texas, and the Parties hereby waive any defense of *forum non-conveniens,* except defenses under Tex. Civ. Prac. & Rem. Code §15.002(b).

B. Assignment.

(1) Notwithstanding anything herein to the contrary, a Party shall not assign or otherwise transfer all or any of its rights or obligations under this Agreement without the prior written consent of the other Party, which shall not be unreasonably withheld or delayed, except that a Party may assign or transfer its rights and obligations under this Agreement without the prior written consent of the other Party (if neither the assigning Party or the assignee is then in Default of any Agreement with ERCOT):

(a) Where any such assignment or transfer is to an Affiliate of the Party; or

(b) Where any such assignment or transfer is to a successor to or transferee of the direct or indirect ownership or operation of all or part of the Party, or its Facilities; or

(c) For collateral security purposes to aid in providing financing for itself, provided that the assigning Party will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by either Party pursuant to this Section will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). If requested by the Party making any such collateral assignment to a Financing Person, the other Party shall execute and deliver a consent to such assignment containing customary provisions, including representations as to corporate authorization, enforceability of this Agreement and absence of known Defaults, notices of Default, and an opportunity for the Financing Person to cure Defaults.

(2) An assigning Party shall provide prompt written notice of the assignment to the other Party. Any attempted assignment that violates this Section is void and ineffective. Any assignment under this Agreement shall not relieve either Party of its obligations under this Agreement, nor shall either Party's obligations be enlarged, in whole or in part, by reason thereof.

C. <u>No Third Party Beneficiary.</u> Except with respect to the rights of other Market Participants in Section 10.B and the Financing Persons in Section 13.B(3), (1) nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, (2) no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder and (3) this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to this Agreement or the services to be provided hereunder. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

D. <u>No Waiver.</u> Parties shall not be required to give notice to enforce strict adherence to all provisions of this Agreement. No breach or provision of this Agreement shall be deemed waived, modified or excused by a Party unless such waiver, modification or excuse is in writing and signed by an authorized officer of such Party. The failure by or delay of either Party in enforcing or exercising any of its rights under this Agreement shall (1) not be deemed a waiver, modification or excuse of such right or of any breach of the same or different provision of this Agreement, and (2) not prevent a subsequent enforcement or exercise of such right. Each Party shall be entitled to enforce the other Party's covenants and promises contained herein, notwithstanding the existence of any claim or cause of action against the enforcing Party under this Agreement or otherwise.

E. <u>Headings.</u> Titles and headings of paragraphs and sections within this Agreement are provided merely for convenience and shall not be used or relied upon in construing this Agreement or the Parties' intentions with respect thereto.

F. <u>Severability.</u> In the event that any of the provisions, or portions or applications thereof, of this Agreement is finally held to be unenforceable or invalid by any court of competent jurisdiction, that determination shall not affect the enforceability or validity of the remaining portions of this Agreement, and this Agreement shall continue in full force and effect as if it had been executed without the invalid provision; provided, however, if either Party determines, in its sole discretion, that there is a material change in this Agreement by reason thereof, the Parties shall promptly enter into negotiations to replace the unenforceable or invalid provision with a valid and enforceable provision. If the Parties are not able to reach an agreement as the result of such negotiations within fourteen (14) days, either Party shall have the right to terminate this Agreement on three (3) days written notice.

G. <u>Entire Agreement.</u> Any Exhibits attached to this Agreement are incorporated into this Agreement by reference and made a part of this Agreement as if repeated verbatim in this Agreement. This Agreement represents the Parties' final and mutual understanding with respect to its subject matter. It replaces and supersedes any Prior Agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by any Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement. An agreement, statement, or promise not contained in this Agreement is not valid or binding.

H. Amendment. The standard form of this Agreement may only be modified through the procedure for modifying ERCOT Protocols described in the ERCOT Protocols. Any changes to the terms of the standard form of this Agreement shall not take effect until a new Agreement is executed between the Parties.

I. ERCOT's Right to Audit Participant. Participant shall keep detailed records for a period of three years of all activities under this Agreement giving rise to any information, statement, charge, payment, or computation delivered to ERCOT under the ERCOT Protocols. Such records shall be retained and shall be available for audit or examination by ERCOT as hereinafter provided. ERCOT has the right during Business Hours and upon reasonable written notice and reasonable cause to examine the records of Participant as necessary to verify the accuracy of any such information, statement, charge, payment, or computation made under this Agreement. If any such examination reveals any inaccuracy in any information, statement, charge, payment, or computation, the necessary adjustments in such information, statement, charge, payment, computation, or procedures used in supporting its ongoing accuracy will be promptly made.

J. Participant's Right to Audit ERCOT. Participant's right to data and audit of ERCOT shall be as described in the ERCOT Protocols and shall not exceed the rights described in the ERCOT Protocols.

K. Further Assurances. Each Party agrees that during the Term of this Agreement it will take such actions, provide such documents, do such things, and provide such further assurances as may reasonably be requested by the other Party to permit performance of this Agreement.

L. Conflicts. This Agreement is subject to applicable federal, state, and local laws, ordinances, rules, regulations, orders of any Governmental Authority, and tariffs. Nothing in this Agreement may be construed as a waiver of any right to question or contest any federal, state and local law, ordinance, rule, regulation, order of any Governmental Authority, or tariff. In the event of a conflict between this Agreement and an applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff, the applicable federal, state, and local law, ordinance, rule, regulation, order of any Governmental Authority or tariff shall prevail, provided that Participant shall give notice to ERCOT of any such conflict affecting Participant. In the event of a conflict between the ERCOT Protocols and this Agreement, the provisions expressly set forth in this Agreement shall control.

M. No Partnership. This Agreement may not be interpreted or construed to create an association, joint venture, or partnership between the Parties or to impose any partnership obligation or liability upon either Party. Neither Party has any right, power, or authority to enter any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party except as provided in Section 9.A.

N. Construction. In this Agreement, the following rules of construction apply, unless expressly provided otherwise or unless the context clearly requires otherwise:

(1) The singular includes the plural, and the plural includes the singular.

(2) The present tense includes the future tense, and the future tense includes the present tense.

(3) Words importing any gender include the other gender.

(4) The word "shall" denotes a duty.

(5) The word "must" denotes a condition precedent or subsequent.

(6) The word "may" denotes a privilege or discretionary power.

(7) The phrase "may not" denotes a prohibition.

(8) References to statutes, tariffs, regulations or ERCOT Protocols include all provisions consolidating, amending, or replacing the statutes, tariffs, regulations or ERCOT Protocols referred to.

(9) References to "writing" include printing, typing, lithography, and other means of reproducing words in a tangible visible form.

(10) The words "including," "includes," and "include" are deemed to be followed by the words "without limitation."

(11) Any reference to a day, week, month or year is to a calendar day, week, month, or year unless otherwise indicated.

(12) References to Articles, Sections (or subdivisions of Sections), Exhibits, annexes, or schedules are to this Agreement, unless expressly stated otherwise.

(13) Unless expressly stated otherwise, references to agreements, ERCOT Protocols and other contractual instruments include all subsequent amendments and other modifications to the instruments, but only to the extent the amendments and other modifications are not prohibited by this Agreement.

(14) References to persons or entities include their respective successors and permitted assigns and, for governmental entities, entities succeeding to their respective functions and capacities.

(15) References to time are to Central Prevailing Time.

O. Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED, AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Agreement.

Electric Reliability Council of Texas, Inc.:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Participant:

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

ERCOT Nodal Protocols

Section 22

Attachment C: Amendment to Standard Form Market Participant Agreement

Updated: March 1, 2008

(Effective upon the Nodal Protocol Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

Amendment to
Standard Form Market Participant Agreement
Between
[Participant]
and
Electric Reliability Council of Texas, Inc.

This AMENDMENT to the Standard Form Market Participant Agreement ("Amendment"), effective as of the ____________ day of ______________________, ____________ ("Effective Date"), is entered into by and between [Participant], a [State of Registration and Entity Type] ("Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").

Recitals

WHEREAS, Participant and ERCOT entered into a Standard Form Market Participant Agreement (SFA) dated _______________; and

WHEREAS, Participant and ERCOT wish to amend that SFA to include Market Participant registrations designated below.

NOW, THEREFORE, Participant and ERCOT agree that paragraph A in the "Recitals" section of that SFA shall be deleted in its entirety and replaced with the following:

A. As defined in the ERCOT Protocols, Participant is a (check all that apply):

☐ Load Serving Entity (LSE)

☐ Qualified Scheduling Entity (QSE)

☐ Transmission Service Provider (TSP)

☐ Distribution Service Provider (DSP)

☐ Congestion Revenue Right (CRR) Account Holder

☐ Resource Entity

☐ Renewable Energy Credit (REC) Account Holder

This Amendment modifies the existing SFA only to include those Market Participant registrations designated above by Participant.

This Amendment in no way alters the terms and conditions of the existing SFA other than as specifically set forth herein.

SIGNED, ACCEPTED AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that he or she has full power and authority to execute this Amendment to the Standard Form Market Participant Agreement.

Electric Reliability Council of Texas, Inc.:

By: ____

Name: ____

Title: ____

Date: ____________________________

Participant:

[USE OPTION 1 IF PARTICIPANT IS A CORPORATION

By: ____

Name: ____

Title: ____

Date:_______________________________

USE OPTION 2 IF PARTICIPANT IS A LIMITED PARTNERSHIP

By: ____,
as General Partner for [Participant]

Name:____

Title:____

Date:____

Market Participant Name:
____

Market Participant DUNS: ___________________

ERCOT Nodal Protocols

Section 22

Attachment K: Standard Form Emergency Interruptible Load Service (EILS) Agreement

Updated: August 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date, as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

Standard Form Emergency Interruptible Load Service (EILS)
Supplement to Market Participant Agreement
Between
(Name of Participant)
and
Electric Reliability Council of Texas, Inc.

This Supplement to Market Participant Agreement ("Supplement"), effective as of [START DATE] ("Start Date"), is entered into by and between [PARTICIPANT's NAME], a Qualified Scheduling Entity in the ERCOT Region ("QSE" or "Participant") and Electric Reliability Council of Texas, Inc., a Texas non-profit corporation ("ERCOT").[1]

<u>Recitals</u>

WHEREAS:

A. The Public Utility Commission of Texas ("PUCT") instituted its Substantive Rule 25.507, "Electric Reliability Council of Texas (ERCOT) Emergency Interruptible Load Service" ("EILS Rule") providing for the creation of a special emergency service known as Emergency Interruptible Load Service ("EILS"); and

B. Participant is a QSE in the ERCOT Region and has executed a Standard Form Market Participant Agreement ("Market Participant Agreement") with ERCOT; and

C. Participant is the QSE representing an entity or entities owning or controlling EILS Load(s) that will be obligated to provide EILS; and

D. Participant and ERCOT wish to supplement the Market Participant Agreement between Participant and ERCOT to provide for Participant to represent EILS Loads wishing to participate in the EILS; and

E. The Parties enter into this Supplement in order to establish the terms and conditions by which ERCOT and Participant will discharge their respective duties and responsibilities with respect to EILS.

<u>Agreements</u>

NOW, THEREFORE, in consideration of the mutual covenants and promises contained herein, ERCOT and Participant (the "Parties") hereby agree as follows:

[1] Unless otherwise indicated, capitalized terms in this Agreement have the meanings ascribed to them in the ERCOT Protocols.

A. All terms and conditions of the Market Participant Agreement between Participant and ERCOT remain in full force and effect.

B. In addition to its obligations under the Market Participant Agreement with ERCOT, Participant will submit offers for EILS on behalf of the entities set forth in Appendix A for a particular Contract Period as described in a Request for Proposal issued by ERCOT.

C. Participant and ERCOT will abide by and comply with the EILS Rule as well as all ERCOT Protocols and Technical Requirements concerning EILS.

D. Participant and ERCOT agree that each award of EILS will be confirmed by a terms and conditions sheet ("Term Sheet") provided by ERCOT to Participant in a form substantially the same as the form attached hereto as Appendix B.

E. Either Party may terminate this Supplement by providing thirty days notice to the other Party; *provided, however,* no termination of this Supplement will be effective before the end of an EILS Contract Period for which ERCOT has already issued a Term Sheet to Participant.

F. This Supplement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

SIGNED, ACCEPTED, AND AGREED TO by each undersigned signatory who, by signature hereto, represents and warrants that s/he has full power and authority to execute this Supplement.

Electric Reliability Council of Texas, Inc.:

By: ____

Printed Name: ____________________________________

Title: ____

Date: ____

Participant:

By: ____

Printed Name:_____________________________________

Title: ____

Date: ____

Appendix A

To Supplement to Market Participant Agreement

The Entity that owns or controls the following EILS Load hereby acknowledges that it understands and will comply with P.U.C. SUBST. R. 25.507 and the ERCOT Protocols relating to Emergency Interruptible Load Service (EILS).

Acknowledgement by EILS Load Owning or Controlling Entity

Company Name

Authorized Representative Name

Title

Address Line1

Address Line 2

City/State/ZIP

Phone

Email Address

[ENTITY NAME]

By:____

[Signature]

Printed Name:__________________________________

Its:____

[Title]

Date:______________________________________

Appendix B

Supplement to Market Participant Agreement for EILS Loads

This Term Sheet is subject to the Market Participant Agreement and EILS Supplement thereto between {QSE Name} and Electric Reliability Council of Texas, Inc., dated MM/DD/YY. The terms of this Term Sheet are binding on both parties.

EMERGENCY INTERRUPTIBLE LOAD SERVICE TERM SHEET			
QSE Name		**QSE DUNS Number**	
Contract Period			
EILS Load Type			
Baseline Methodology (Default or Alternate)			
EILS Time Period (from RFP)			
AWARD AMOUNTS			
Interruptible Capacity (MW)			
Price ($/MW) to be applied to each hour of the contract period			
Minimum Base Load (MW) associated with this EILS Load that will not be interrupted as part of the EILS deployment			

A. Individual EILS Load Data

Electric Service Identifier (ESI ID) or unique service identifier assigned to meter (MUST BE Interval Data Recorder (IDR))	
Load Owner/Operator	
Load Common Name	
Meter Reading Entity (TDSP)	
Meter Reading Entity DUNS Number	
Load within a NOIE Service Area (Y or N)	
Load within a Private Use Network (Y or N)	

B. Aggregated EILS Load Data

ESI ID or unique service identifier assigned to meter (MUST BE IDR)	EILS Load Owner or Operator	EILS Load Common Name	Meter Reading Entity (TDSP)	Meter Reading Entity DUNS Number	Within a NOIE Service Area	Within a Private Use Network

ESI ID or unique service identifier assigned to meter (MUST BE IDR)	EILS Load Owner or Operator	EILS Load Common Name	Meter Reading Entity (TDSP)	Meter Reading Entity DUNS Number	Within a NOIE Service Area	Within a Private Use Network

ESI ID or unique service identifier assigned to meter (MUST BE IDR)	EILS Load Owner or Operator	EILS Load Common Name	Meter Reading Entity (TDSP)	Meter Reading Entity DUNS Number	Within a NOIE Service Area	Within a Private Use Network

C. Non-IDR Aggregated EILS Load Data

Description of EILS Load (Aggregation population)	
EILS Load Owner/Operator	
EILS Load Common Name	
Meter Reading Entity (TDSP)	
Meter Reading Entity DUNS Number	
Load within a NOIE Service Area (Y or N)	
Load within a Private Use Network (Y or N)	

ERCOT Nodal Protocols

Section 23: Texas Test Plan Team - Retail Market Testing

Updated: July 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's]() Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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23 TEXAS TEST PLAN TEAM – RETAIL MARKET TESTING

This Section contains an overview of the purpose and scope of the Texas Test Plan Team (TTPT). It also refers to the standards that are defined in the Texas Market Test Plan (TMTP) posted on the ERCOT Market Information System (MIS) Public Area. This Section applies to ERCOT, Competitive Retailers (CR), and Transmission and/or Distribution Service Providers (TDSP) serving areas where Customer Choice is in effect.

23.1 Overview

(1) The Texas Test Plan Team (TTPT) is an ERCOT standing working group that reports to the Retail Market Subcommittee (RMS). The TTPT is comprised of volunteers from Market Participant companies. These volunteers work in a cooperative manner to establish processes and procedures for testing the commercial operations to verify retail systems are in compliance with the ERCOT Protocols and Public Utility Commission of Texas (PUCT) Substantive Rules.

(2) The TTPT processes and procedures for testing represent the consensus view of Market Participants directly involved in the testing process.

(3) The TTPT evaluates market processes defined by the ERCOT Protocols, other RMS working groups, and PUCT Substantive Rules to establish testing requirements and materials necessary to validate those processes among Market Participants.

(4) The TTPT works with the ERCOT flight administrator to ensure that testing processes and procedures are defined for the ERCOT market and that the content of those materials are thoroughly and equitably administered with all participants. The ERCOT flight administrator is the final authority on all levels of business process certification among trading partners, including the verification that a party has successfully passed testing and is eligible to go into production.

23.2 Testing Participants

The following parties conduct market compliance testing and abide by the testing process defined by the Texas Test Plan Team (TTPT):

(a) ERCOT;

(b) Transmission and/or Distribution Service Provider (TDSP); and

(c) Competitive Retailer (CR).

23.3 Documentation and Testing Materials

The Texas Test Plan Team (TTPT) develops and maintains a test plan and related testing standards. The processes and procedures for testing are defined in the Texas Market Test Plan (TMTP) posted on the ERCOT Market Information System (MIS) Public Area.

23.4 Market Changes

The Texas Test Plan Team (TTPT) stays abreast of changes within the ERCOT market (e.g. Texas Standard Electronic Transaction (TX SET) Implementation Guides, Texas Data Transport Working Group (TDTWG) communication protocols, ERCOT Protocols, and Public Utility Commission of Texas (PUCT) Substantive Rules) and develops testing processes to validate changes. When such changes occur, the TTPT modifies the testing standards defined in the Texas Market Test Plan (TMTP) as needed to provide for adequate testing of all affected market systems. Testing of these changes is scheduled to allow ERCOT and all Market Participants adequate time to modify their systems and participate in the testing process.

23.5 Testing Success

Testing success is defined according to the information in the Texas Market Test Plan (TMTP) and the test scripts. The ERCOT flight administrator is the final authority on all levels of business process certification among trading partners, including the verification that a party has successfully passed testing and is eligible to go into production.

ERCOT Nodal Protocols

Section 24: Retail Point to Point Communications

Updated: July 1, 2008

(Effective upon the [Nodal Protocol Transition Plan's](#) Texas Nodal Market Implementation Date as prescribed by zonal Protocol Section 21.12, Process for Transition to Nodal Market Protocol Sections)

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24 RETAIL POINT TO POINT COMMUNICATIONS

Point to point communications include transactions flowing directly between Competitive Retailers (CRs), and Transmission and/or Distribution Service Providers (TDSPs) and do not flow through ERCOT. These point to point transactions may be Customer requested service orders and CR/TDSP invoicing and remittance.

24.1 Maintenance Service Order Request

To initiate an original service order, cancel, or change (update) request, the Competitive Retailer (CR) sends maintenance related information to the Transmission and/or Distribution Service Provider (TDSP) using the 650_01, Service Order Request. The 650_01 sent by the CR shall include a level of information such that the TDSP clearly understands the nature of the request and the work that it is being requested to perform. The TDSP will respond within one Retail Business Day after completion, or attempted completion, of the requested action using the 650_02 to notify the CR that the service order is either completed, unable to be completed, or rejected, or that a permit is required before the order can be completed. There is a one-to-one relationship between the 650_01 and 650_02 service order request/response transactions.

24.1.1 Disconnect/Reconnect

Public Utility Commission of Texas (PUCT) Substantive Rules and orders, along with TDSP Tariffs, dictate the timeline for both disconnection for non-payment and reconnection after disconnection for non-payment. For more information please refer to the Retail Market Guide Section 7.6, Disconnect and Reconnect for Non-Payment Process.

24.1.2 Suspension of Delivery Service

The following transactions shall be used by a TDSP seeking to suspend delivery service for an Electric Service Identifier (ESI ID).

24.1.2.1 Notification

(1) The 650_04, Suspension of Delivery Service Notification, transaction is electronically transmitted by the TDSP to the CR to notify the CR of the ESI ID(s) and Service Address(es) affected by either a temporary or permanent suspension of service. The situations under which a 650_04 transaction may be created and transmitted to the CR include:

(a) An outage has been scheduled by the TDSP for the Customer's Service Address for a specific date and time. This type of suspension may be the result of scheduled tree trimming, electrical inspection, testing, maintenance, or changes/upgrades to network equipment.

(b) An outage has occurred at the Customer's Service Address, but it was not planned or previously scheduled. Such a suspension is normally needed to remedy a dangerous electrical condition that exists at the Customer's address due to an event or activity such as a fire, meter tampering, or theft of service.

(c) For circumstances when a CR, the Customer, or authorized legal authority (county, city, fire, or police personnel) requests disconnection and meter removal because a structure has been destroyed or demolished, or the TDSP has found the meter removed by an unknown entity, or has removed the meter for unsafe conditions, the TDSP will send a 650_04. In events where the CR receives a 650_04 indicating that service to the Premise has been permanently suspended by the TDSP for one of the reasons indicated above, the CR will send an 814_24, Move-Out Request, to the TDSP within ten Retail Business Days.

(d) Just like a suspension is scheduled or requested it can also be cancelled. If the suspension request is cancelled for any reason, the TDSP will create a 650_04 Notification indicating that the suspension has been cancelled and send a 650_04 Notification to the CR for every ESI ID that would have been affected by the outage.

(2) To notify the CR of a suspension of delivery service, the TDSP sends Notice to the CR using the 650_04. To reject the suspension of delivery service Notification, a CR would send a response to the TDSP using the 650_05, Suspension of Delivery Service Reject Response, within one Retail Business Day of receipt of the 650_04.

24.1.2.2 Cancellation

To notify the CR of a cancellation of the Notification of suspension of delivery service, the TDSP sends Notice to the CR using the 650_04 for each ESI ID that would otherwise have been affected by the outage. To reject the suspension of delivery service cancellation, a CR must send a response to the TDSP using the 650_05 within one Retail Business Day of receipt of the 650_04.

24.2 Transmission and/or Distribution Service Provider to Competitive Retailer Invoice

(1) The 810_02, Transmission and/or Distribution Service Provider (TDSP) to Competitive Retailer (CR) Invoice, may include monthly delivery charges, discretionary service charges, service order charges, interest credit, and/or late payment charges for the current billing period. Following a positive acknowledgement indicating the transaction passed ANSI X12 validation, the CR shall have five Business Days to send a rejection response in accordance with the Texas Standard Electronic Transaction (TX SET) Implementation Guides posted on the ERCOT Market Information System (MIS) Public Area and Public Utility Commission of Texas (PUCT) Substantive Rules. If the CR has not received a response transaction to an enrollment or move-in, the CR shall not reject the invoice, but will utilize an approved market process (MarkeTrak or Dispute Process) to resolve the

issue. Details of these processes may be found in the Retail Market Guide Section 7, Market Processes.

(2) Only one 810_02 may be sent for a single service period, however, any additional 810_02 for the same Electric Service Identifier (ESI ID) may be sent for a late payment charge after the 35th calendar day for an unpaid 810_02 or for interest credit.

(3) The 810_02 may be paired with an 867_03, Monthly Usage, to trigger the Customer billing process.

(4) The TDSP may cancel and replace (rebill) the original 810_02. The values in the cancel transaction will be identical in amounts to what they were on the original invoice. The replacement (rebilled) invoice now becomes the monthly invoice for that service period.

(5) If the 867_03 is cancelled after the TDSP has sent the 810_02, the TDSP will cancel the 810_02. If the 810_02 error is not related to consumption, the TDSP may cancel the 810_02 and not the 867_03.

24.3 Monthly Remittance

Transmission and/or Distribution Service Providers (TDSPs) and Competitive Retailers (CR) shall use the following transactions to remit monthly payments.

24.3.1 CR to TDSP Monthly Remittance Advice

(1) This transaction set, from the CR to the TDSP, is used by the CR to notify the TDSP of payment details related to a specific invoice. A CR must pass an 820_02, CR Remittance Advice, for every invoice (original, cancel, replacement) received, validated, and accepted by the CR even when a cancel and restatement of usage subsequently cancels the original invoice.

(2) Each Market Participant is responsible for ensuring that the data provided in the 820_02 is presented in a format that is consistent with market specifications prescribed in the Texas Standard Electronic Transaction (TX SET) 820_02 Implementation Guide posted on the ERCOT Market Information System (MIS) Public Area.

24.3.1.1 Remittance Advice Total Matches Payment Total

The remittance advice must match the total payment. The CR must ensure that the remittance advice and the payment instructions have the same (matching) trace/reference numbers. A one-to-one correlation must be maintained between payments and remittance advices. It is acceptable for one payment and one remittance advice to include many invoices. It is not acceptable for several payments to reference one remittance advice. Every payment trace/reference number sent via the bank must match a remittance advice trace/reference number sent to the TDSP. The trace/reference number must be unique for each associated payment and remittance advice.

24.3.1.2 Negative Remittance Advice

A negative remittance advice is not allowed in the Texas retail market. If the adjustments are larger than the payments (creating a negative remittance advice), payments must be held until the CR can submit a net positive remittance advice as a credit against the overpayment. It is not necessary for a CR to hold an adjustment amount until the CR has accumulated sufficient invoices to result in a complete offset of the overpayment. Instead the CR may use the adjustment amount by taking a partial credit on another Invoice. If the CR has determined that the negative remittance cannot be offset within a reasonable amount of time, the CR will contact the TDSP to resolve the situation.

24.3.1.3 Acceptable Payment Methods

Acceptable payment methods are CCD+, CTX and Fed wire.

24.3.1.4 Warehousing an 820 Remittance Advice

When the payment instruction and the remittance advice are generated separately, the TDSP will warehouse the 820_02 until the payment instructions received by the CR's bank cause the money to be deposited in the TDSP's account. The payment instruction and remittance shall be transmitted within five Business Days of each other. The remittance advice and payment instruction dollar amount must balance to the corresponding transaction. Payment will be considered received on the date company's bank receives the electronic funds transfer or wire transfer and the appropriate remittance advice is received by the company in accordance with the requirements specified by Applicable Legal Authorities (ALA).

24.4 MOU/EC TDSP to CR Monthly Remittance Advice

(1) This transaction set, from a Municipally Owned Utility's (MOU) Transmission and/or Distribution Service Provider (TDSP) or an Electric Cooperative's (EC) TDSP (MOU/EC TDSP) to the Competitive Retailer (CR) is used by the MOU/EC TDSP to notify the CR of payment details related to a specific Invoice. A MOU/EC TDSP must pass an 820_03, Remittance Advice, for every CR account number even when a cancel and restatement of usage subsequently cancels the original invoice.

(2) Each Market Participant is responsible for ensuring that the data provided in the 820_03 is presented in a format that is consistent with the market specifications in the Texas Standard Electronic Transaction (TX SET) Implementation Guide.

24.4.1 Timing 820 Remittance to CR

When the payment is received from the retail Customer on behalf of the CR, MOU/EC TDSP shall send the payment instructions within five Retail Business Days of the due date of the retail Customer's bill, or if the Customer has paid after the due date, five Business Days after the MOU/EC TDSP has received payment. Payment instruction shall cause the money to be deposited in the CR's account. There should not be more than five Business Days difference in the receipt of the payment instruction and the remittance advice.

24.4.2 Remittance Advice Total Matches Payment Total

The remittance advice must match the total payment. The MOU/EC TDSP must ensure that the remittance advice and the payment instructions have the same (matching) trace/reference numbers. A one-to-one correlation must be maintained between payments and remittance advice. It is acceptable for one payment and one remittance advice to include many invoices. It is not acceptable for several payments to reference one remittance advice. Every payment trace/reference number sent via the bank must match a remittance advice trace/reference number sent to the CR. The trace/reference number must be unique for each associated payment and remittance advice.

24.4.3 Negative Remittance Advice

A negative remittance advice is not allowed in the Texas market. If the adjustments are larger than the payments (creating a negative remittance advice), payment must be held until the MOU/EC TDSP can submit a net positive remittance advice as a credit against the overpayment. It is not necessary for a MOU/EC TDSP to hold an adjustment amount until the MOU/EC TDSP has accumulated sufficient Invoices to result in a complete offset of the overpayment. Instead the MOU/EC TDSP may use the adjustment amount by taking a partial credit on another Invoice. If the MOU/EC TDSP has determined that the negative remittance cannot be offset within a reasonable amount of time, the MOU/EC TDSP will contact the CR to resolve the situation.

24.4.4 Acceptable Payment Methods

Acceptable payment instruction methods are CCD+, CTX, check, and Fed wire.

24.4.5 Warehousing an 820 Remittance Advice

When the payment instruction and the remittance advice are generated separately, the CR may warehouse the 820_03 remittance until the payment instructions received by the MOU/EC TDSP's bank cause the money to be deposited in the CR's account.

24.5 Maintain Customer Information Request

This transaction set, from a Competitive Retailer (CR) to a Transmission and/or Distribution Service Provider (TDSP), is used for CRs who have chosen Options 2 and 3 concerning service orders and/or outages. A CR choosing Option 2 or 3 shall be required to provide the TDSP with the information necessary to verify CR's retail Customer's identity (name, address, and home or contact telephone number) for a particular point of delivery served by the CR and to continually provide the TDSP updates of such information.

24.5.1 Timing of 814_PC Maintain Customer Information Request from CR

This transaction shall be transmitted from the CR of Record to the TDSP in one Retail Business Day only after the CR has received an 867_04, Initial Meter Read Notification, from the TDSP for that specific move-in Customer. Also, the CR shall not transmit this transaction and/or provide any updates to the TDSP after receiving a final reading via an 867_03, Monthly Usage, for that specific move-out Customer. The TDSP shall provide the 814_PD, Maintain Customer Information Response, transaction in one Retail Business Day acknowledging receipt of the 814_PC, Maintain Customer Information Request, transaction which would indicate that the TDSP accepts or rejects the transaction.

24.6 MOU/EC TDSP to CR Maintain Customer Information Request

This transaction set, from a Municipally Owned Utility (MOU)/Electric Cooperative (EC) Transmission and/or Distribution Service Provider (TDSP) to the Competitive Retailer (CR), is used by the MOU/EC TDSP to provide the CR with Customer information (name, address, membership id, and home or contact telephone number) for a particular point of delivery served by both the MOU/EC TDSP and CR and to continually provide the CR updates of such information. MOU/EC TDSPs in a MOU/EC service territory are more likely to have current Customer information due to the fact that they maintain contact with the Customer and perform billing functions.

24.6.1 Timing of 814_PC Maintain Customer Information Request from MOU/EC TDSP

This transaction shall be transmitted from the MOU/EC TDSP to the CR in one Retail Business Day upon an update in Customer information. The CR shall provide the 814_PD transaction in one Retail Business Day acknowledging receipt of the 814_PC transaction, which would indicate that the CR accepts or rejects the transaction.