PROJECT NO. 23157

RULEMAKING PROCEEDING TO REVISE PUC TRANSMISSION RULES CONSISTENT WITH THE NEW ERCOT MARKET DESIGN	**§ § § § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING NEW AND AMENDED TRANSMISSION RULES AND REPEALING CERTAIN RULES CONSISTENT WITH THE NEW ERCOT MARKET DESIGN AS APPROVED AT THE MAY 24, 2001 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts two new rules and amendments to various sections of the commission's substantive rules in Chapter 25, Subchapter A, General Provisions, Subchapter I, Transmission and Distribution, and Subchapter O, Unbundling and Market Power, and repeals five sections of Subchapter I, as published in the March 9, 2001 *Texas Register* (26 TexReg 1932). The new rules, amendments and repeals are necessary to revise the commission's transmission rules consistent with the new market design developed by the Electric Reliability Council of Texas (ERCOT). These new rules, amendments, and repeals are adopted under Project Number 23157.

These sections are adopted with changes to the text as proposed: amendments to §25.5, relating to Definitions, §25.191, relating to Transmission Service Requirements, §25.192, relating to Transmission Service Rates; new §25.193, relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF); amendments to §25.195, relating to Terms and Conditions for Transmission Service, §25.196, relating to Standards of Conduct (formerly Functional Unbundling), §25.198, relating to Initiating Transmission Service, §25.200, relating to Load Shedding, Curtailments, and Redispatch, §25.202, relating to Commercial Terms for

Transmission Service, §25.203, relating to Alternative Dispute Resolution (ADR); and new §25.361, relating to Electric Reliability Council of Texas (ERCOT).

These repeals are adopted with no changes as proposed: §25.193, relating to Procedures for Modifying Transmission Rates, §25.194, relating to Determining Peak Load and Transmission Adequacy, §25.197, relating to ERCOT Independent System Operator, §25.201, relating to Ancillary Services, and §25.204, relating to Summary of Required Filings.

A public hearing on the proposal was held at commission offices on April 16, 2001 at 9:30 a.m. Representatives from Central Power and Light Company and West Texas Utilities Company (the AEP ERCOT Companies, (AEP)), Competitive Assets and Constellation (Constellation), East Texas Cooperatives, Electric Reliability Council of Texas (ERCOT), FPL Energy (FPLE), Reliant Energy (Reliant), South Texas Electric Cooperative (STEC), Texas Electric Cooperatives (TEC), and TXU Electric Company (TXU) attended the hearing and provided comments. To the extent that these comments differ from the submitted written comments, such comments are summarized herein.

The commission received comments on the proposed new sections and amendments from AEP, Brazos Electric Power Cooperative (Brazos), Cap Rock Electric Cooperative (Cap Rock), City of Austin d/b/a Austin Energy (Austin), City of Brownsville Public Utilities Board (Brownsville), City of Garland and City of Denton (Garland/Denton), City of Granbury (Granbury), City Public Service Board of San Antonio (San Antonio), ERCOT, FPLE, Greenville Electric Utility System (Greenville), Lower Colorado River Authority (LCRA), Mirant Americas Energy Marketing

(Mirant), Nucor Steel (Nucor), Reliant, STEC, Tex-La Electric Cooperative of Texas (Tex-La), Texas Municipal Power Agency (TMPA), TEC, Texas Industrial Energy Consumers (TIEC), and TXU.

Upon publication of the proposed rules, the commission requested comments on two preamble questions. Comments and responses to these questions are addressed in the context of relevant rule sections. Question Number 1 is addressed in the discussion of §25.196(d). Question Number 2 is addressed in §25.195.

Subchapter A. General Provisions.

§25.5. Definitions.

The commission recognizes that common meanings of the terms "wholesale" and "retail" with regard to the provision of transmission service will inevitably shift as the market is restructured. Applied to transmission service, the commission regards the "retail" transmission service activity as the sale of transmission service to a retail electric provider (REP). This is addressed by §25.214 relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities, with an accompanying tariff for delivery service applicable to investor-owned utilities (IOUs). Another rule addressing municipally owned utilities (MOUs) and electric cooperatives (cooperatives) will complement it. Such retail transmission service activity is not the activity governed by the rules adopted in this proceeding. The rules adopted in this proceeding concern the activity among generation entities, transmission entities, and distribution entities, which can be said to be "wholesale" transmission service. This rule gives REPs a right to transmission service, but the terms and conditions for a REP taking delivery service are set out in the tariff adopted under §25.214. In order not to constrain the evolution of these terms in the new market design, the commission refrains from defining the terms "wholesale" and "retail" in these rules.

Proposed definitions (20) Distribution service provider (DSP) and (81) Transmission service provider (TSP) (now (82))

TMPA, Greenville, Cap Rock, Garland/Denton, LCRA, and Tex-La said the definition of Distribution Service Provider (DSP) is too broad for the purposes of the transmission rules because the definition inappropriately includes non-opt-in entities (NOIEs), electric cooperatives and MOUs. TEC said the proposed DSP definition would impose unnecessary requirements on electric distribution cooperatives that choose not to participate in customer choice and that do not provide wholesale distribution service. TEC said electric distribution cooperatives plan, construct, operate and maintain their distribution facilities and systems for the sole purpose of serving their members and are not obligated to provide open-access distribution service (except for wholesale service). TEC noted the services provided to the cooperative's members are not subject to the commission's jurisdiction. TEC, supported by Tex-La, proposed that the definition be changed to exclude NOIEs, and suggested language to limit DSPs to entities that "offer customer choice" and that "provide wholesale transmission service over distribution facilities."

TXU disagreed that the definition is too broad by including both opt-in and non-opt-in entities (NOIEs), and contended that it covers precisely the entities it should cover for two reasons: First, DSPs or their agents will be receiving invoices for wholesale transmission service from TSPs and will be obligated to pay them, regardless of whether the entity has opted in or not. Second, the Public Utility Regulatory Act (PURA) §31.002 defines "transmission service" as including "transmission over distribution facilities." TXU argued that distribution facilities are the facilities owned by a DSP, wholesale transmission service necessarily includes transmission over distribution facilities and is governed by PURA Chapter 35, Subchapter A, in which "electric utility" is defined to include MOUs and electric cooperatives, and the commission is granted authority over such utilities to provide "nondiscriminatory access to wholesale transmission service." TXU argues that in the rules to implement these provisions of PURA, the commission's definition of DSP must be broad enough to capture every entity subject to its jurisdiction in this respect, regardless of whether the entity has opted in to retail competition or not.

The commission agrees with TXU that the definition should include all entities within its jurisdiction under PURA Chapter 35, Subchapter A. The definition includes electric cooperatives and MOUs that have not opted in to competition. Where substantive rules adopted here do not apply to non-opt-in entities, the published rule provisions are amended to that effect. Therefore, the suggestion by TEC and Tex-La to exclude NOIEs from the definition is not adopted.

Several parties suggested language referencing voltage levels as a distinguishing feature of DSPs. TXU suggested the DSP and TSP definitions should be modified for clarity, and for consistency with the respective definitions of "distribution line" and "transmission system," to explicitly state that distribution facilities operate at voltages below 60 kilovolts and transmission facilities operate at voltages at or above 60 kilovolts. AEP agreed with this suggestion.

The commission does not agree that the DSP and TSP definitions should incorporate voltage level distinctions or that they should not overlap. For rate purposes, 60 kilovolts is the demarcation between transmission and distribution. For other purposes, however, a functional definition is appropriate. A TSP is a company that owns facilities for the transmission of electricity. The bulk of this service is performed by facilities that operate at voltages above 60 kilovolts, but some of it is provided through lower-voltage facilities. Similarly a DSP may provide distribution service at transmission voltage levels, although it operates primarily at lower voltages.

LCRA addressed the incorporation of wholesale and voltage distinctions into the definition by suggesting that the term "Delivery Service Provider" should be used instead of "Distribution Service Provider" to reflect that such entities provide delivery service rather than just distribution service. LCRA argued that the term "distribution" implies that the definition excludes service provided at transmission-level voltage, which would be inaccurate because retail service can be requested and made at transmission-level voltage under §25.214 and §25.215, and the accompanying tariffs. LCRA was concerned that the use of the word "distribution" could lead to a conclusion that retail delivery service provided at transmission-level voltage should not be included in the load attributed to the DSP for purposes of setting wholesale transmission rates and billing for such wholesale transmission service. LCRA explained that, in the restructured world, transmission providers will only bill wires entities that deliver electricity to end-use retail customers and not end-use customers themselves, regardless of the voltage level at which the customers take service. LCRA said that the rules and tariffs proposed and adopted by the commission for retail delivery service (§25.214 and §25.215) make it clear that load-serving entities will have to provide delivery service at transmission level if requested by an end-use customer. The commission's pricing scheme for wholesale transmission service will work only if all retail load is accounted for and assigned to a DSP (or TDSP as used in the protocols), regardless of the voltage level at which the end-use customer is connected.

While the commission does not find it appropriate to changed the term "distribution service provider" to "delivery service provider", the commission concludes that LCRA's description of future billing arrangements is accurate and does not adopt the voltage-level distinction suggested by other parties.

Tex-La explained how its configuration as a generation and transmission cooperative serving member cooperatives both inside and outside of ERCOT means that is neither a DSP nor TSP under the proposed definitions and it falls between the cracks for purposes such as billing.

The revised and adopted definitions speak to ownership or operation of certain facilities, and do not speak to whether they are located within ERCOT.

Proposed definitions (24) Eligible transmission service customer (TSC) (now deleted) and (80) Transmission service customer (now (81))

TXU recommended eliminating proposed §25.5(24) and modifying the definition of "transmission service customer" to include the entities who are entitled to service. TXU maintains that only the term "transmission service customer" is plainly needed because, as the transmission rules have been implemented, the distinction between these two terms has lost any meaningful significance. TMPA, Greenville, Cap Rock, Garland/Denton, and Austin expressed similar views.

The commission agrees with parties that a single definition of transmission service customer (TSC) will suffice and that a separate definition of "eligible TSC" is no longer needed.

Several parties preferred a specific articulation of the entities that could be a transmission service customer and urged the deletion of the amendment concerning billing transmission service. TXU said the proposed language should be modified by retaining the existing reference to "electric utility" to ensure that the definition of "eligible transmission service customer" includes transmission service providers and distribution service providers that are electric utilities and river authorities. TXU explained that it is necessary to include all of those entities within the definition because the term is used in various sections, such as the billing and payment and indemnification and liability provisions of §25.202, where it clearly needs to include transmission service providers and distribution service providers that are electric utilities and river authorities.

TXU argued that it is important to remember that the transmission rule is a wholesale rule and, even after retail competition commences, it will continue to apply to certain aspects of the wholesale transmission and distribution service provided between an electric cooperative, for example, and a transmission service provider or distribution service provider that is an electric utility. TXU noted that, in a situation involving the interconnection of transmission or distribution lines, the transmission service provider or distribution service provider that is an electric utility may well be the "transmission service customer" under the rule entitled to protection under §25.202.

TEC said the definition's reference to the customer "that is taking transmission service," creates ambiguities in the rule created because it begs the question of who is taking service. TEC stressed the importance of clearly defining the term since the proposed rule has numerous references to the transmission service customer with respect to both rights and obligations, which should not be rendered ambiguous on this account. TEC cited proposed §25.198(a) as not being clear as to which entities are required to make an application for transmission service, and §25.191(e)(2) as to not being clear which transmission service customers exporting power are charged the export charges.

Austin suggested the definition should clarify exactly which categories of entities are "transmission service customers" because, otherwise, certain large industrial customers could appear to be a "transmission service customer." Austin noted that, traditionally, "transmission service customers" have been understood to be load serving entities, such as investor-owned utilities (IOUs), MOUs, cooperatives, and qualifying facilities (QFs). Austin cited existing §25.191(b), relating to Nature of transmission service, and emphasized the phrase "allows transmission service customers to use the transmission systems to deliver power from generation resources *to serve their loads*."

The commission agrees that the types of entities that can be TSCs should be listed in the definition to the extent possible.

TMPA, Greenville, Cap Rock, and Garland/Denton thought the definition implied that a transmission service customer could be a retail customer. These parties said that the TSC definition should be modified to delete the discretionary language in the "eligible" definition or to specifically exclude retail customers from the definition. These parties claimed that the language, "or other person whom the commission has determined to be an eligible transmission service customer," leaves it open for the commission to designate retail customers as eligible transmission customers, and therefore enables partial switchovers, which are prohibited by law. These parties also pointed to proposed §25.361(c)(1), which directs ERCOT to determine who is an eligible transmission customer, as another reason for the definition to specifically articulate who is an eligible transmission service customer.

The commission does not agree that all discretion should be removed from the definition, but it agrees that the definition should be clear that it does not include retail customers, as defined in §25.5. The commission adopts language in §25.191(c) to specifically exclude retail customers from the definition and from the discretion contained within the definition.

Many parties objected to the proposed new sentence, which stated "for the purpose of billing for transmission service, a transmission service customer includes an electric utility providing distribution service." TXU said that retaining the comprehensiveness of the term "electric utility" will eliminate the need for the sentence because a DSP can be an eligible transmission service customer for more purposes than simply billing transmission service. TMPA, Greenville, Cap Rock, and Garland/Denton also object to the new language in this definition speaking to billing transmission service, saying the proposal creates confusion as to who will be billed for transmission service. These parties argued that the proposed definition would have the effect of preventing MOUs providing bundled wholesale power from paying for transmission service, given the way the term is used in §25.192(a) and §25.202. These parties claimed that, to the extent customers other than DSPs are included in the definition of an eligible transmission service customer, they are apparently not subject to tariffs and will not be billed. These parties perceive that the proposed rule could preclude certain entities from paying for transmission service, particularly the MOUs providing bundled wholesale power service to other MOUs and cooperatives, to the extent that the proposed amendments apply tariffs and billing procedures only to DSPs as eligible transmission service customers.

The commission concludes that TXU is correct and that the proposed new sentence conveys the suggestion that DSPs are treated as customers only for billing. The sentence is eliminated.

STEC advocated for clarification that a generation and transmission electric cooperative can continue to make all arrangements for transmission service, including payment for its member distribution cooperatives so that it can handle all aspects of transmission service for the members. TXU and ERCOT supported STEC's concern that a TSC may designate an agent to represent it in making arrangements for transmission service.

The commission agrees that the current practice of a TSC designating an agent to represent it in making arrangements for transmission service should be allowed to continue. The commission accepts ERCOT's suggestion and addresses the concern by inserting language into §25.192(d), relating to billing units.

Proposed definition § 25.5(25) -- ERCOT Protocols (now (24))

ERCOT argues that references in the rules to the ERCOT Protocols that include the description "commission-approved" could be misleading and recommends that they be removed from the definition. ERCOT explained that the Protocols that have been approved by the commission include, in Section 21, a revision process that requires ERCOT Board approval for all revisions to the Protocols, at the culmination of an open revision consideration process, but does not require commission approval. ERCOT acknowledged that the revisions may be appealed to the commission and that the ERCOT Protocols are also subject to the "oversight and review" of the commission, and suggested clarification language.

The commission agrees with the argument of ERCOT and adopts language to make it clear that the ERCOT revisions of the protocols are subject to commission oversight.

ERCOT also recommended that "ERCOT region" should be used throughout the transmission rules when referring to the geographic region managed by ERCOT as a single control area instead of "ERCOT," which references the organization. To avoid confusion, ERCOT suggested adding a new definition to the commission rules, tracking the definition adopted in the ERCOT protocols, for the term "ERCOT Region."

The commission adopts ERCOT's recommendation and adds its definition of ERCOT region, now §25.5(25).

Existing definitions (43) Planned resources, (91) Unplanned Resources, and (92) Unplanned Transmission Service, as proposed for deletion

TMPA, Greenville, and Garland/Denton contend that eliminating references to planned and unplanned resources is only appropriate if the new rule takes effect at the beginning of operation of the single control area, because the new transmission rules are meant to coincide with the implementation of the single control area. These parties argue that if the rule takes effect prior to that time, then planned and unplanned service are still relevant, and all references to planned and unplanned resources should be left intact and designed to be phased out upon the successful implementation of the single control area. In another context, LCRA noted that all references in the proposed rules which imply that TSPs will provide ancillary services should be removed inasmuch as TSPs will no longer provide these services.

TMPA, Greenville, and Garland/Denton are correct that the distinction between planned and unplanned service disappears when ERCOT implements a single control area. LCRA is also correct that references implying that TSPs provide ancillary services are inappropriate and the commission deletes such references. To ensure that the status quo is maintained until ERCOT implements a single control area in the ERCOT region, the commission adopts a transition provision in the new §25.200(e) to address this issue, including appropriate definitions and addressing the provision of ancillary services until such time as the single control area is in effect.

Proposed definition (79) Transmission service (now (80))

TMPA, Greenville, Cap Rock, and Garland/Denton contend that the definition must clarify that transmission over distribution facilities is to wholesale customers only and does not include service to retail customers; otherwise, the definition could effectively force non-opt-in utilities to transmit power to another utility's retail customers, which they are not required to do by PURA. These parties' argued that the discretion allowed in the TSC definition could be construed to allow the commission to designate a retail customer as a transmission service customer.

TMPA, Greenville, Cap Rock, and Garland/Denton argue that non-opt-in utilities are not required under PURA to transmit power to another utility's retail customers, either at the transmission voltage level or at the distribution voltage level, and whether or not the retail customer is in a singly or multiply certificated service area. They contend that it must be made clear that "transmission over distribution facilities" is required only when it is to serve a wholesale customer. These parties note that amending the definition of "eligible transmission service customer" to specifically exclude retail customers from the definition could accomplish the appropriate intent of the rules and that compliance with PURA could be attained by providing that transmission service applies only to "*wholesale loads*," "*wholesale* transmission service customers," and "transmission over distribution facilities for *wholesale*."

Brazos agreed with the above parties and argued that the definition could allow retail transmission or distribution service (i.e., retail wheeling) because "transmission services customer" includes REPs, and there is no clear distinction in the proposed rule between wholesale distribution service and retail distribution service. Brazos suggests that inserting "wholesale" at the beginning of the definition is sufficient to clarify that "transmission service" refers to "wholesale transmission service."

Brazos noted that the existing rules extensively use the term "transmission facilities" which was not defined, but was identified in connection with the transmission cost of service provisions in §25.192. Brazos suggested that, for clarification, a definition of "transmission facilities" referencing §25.192(c) and perhaps "distribution facilities" should be included, in lieu of or in addition to the definitions of "transmission system" and "distribution system", respectively, and that the term "facilities" rather than "system" may be a more apt description in both instances for the proposed rule.

The commission notes that parties' arguments concerning the proposed definition of "transmission service" rest on concerns about the proposed definition of TSC in particular and, less directly, the proposed definitions of DSP and TSP. The commission clarifies in §25.191 that an MOU or cooperative that has not opted in to customer choice is not required to provide transmission service to a retail customer in its service area. The commission declines to alter the proposed definition of "transmission service" because other TSPs are required to provide transmission service to facilitate customer choice.

ERCOT suggested in its redline of the rules that the "on and after the implementation of customer choice" trigger in the definition of "transmission service" be qualified by "in any portion of the ERCOT region."

The commission incorporates ERCOT's suggested language to clarify that when customer choice begins in any portion of the ERCOT region, the change in meaning of "transmission service" contemplated by PURA is effective.

River Authority – New Definition (now (66))

LCRA suggests that the commission add a definition of river authority, and provided language, to make it clear that the generic use of the term includes not only the river authority itself, but also any nonprofit corporation created by the river authority that would be regulated by the commission as a transmission and distribution utility. LCRA explained that it must structurally unbundle its generation and transmission functions and will do so by transferring its transmission assets to a nonprofit corporation, which will continue to be a regulated electric utility subject to the same regulatory requirements as LCRA itself if LCRA had retained its transmission assets.

The commission agrees that LCRA's recommended definition would clarify that any non-profit corporation it creates to function as a transmission and distribution utility would be subject to the regulations applicable to a river authority.

SUBCHAPTER I. TRANSMISSION AND DISTRIBUTION.

DIVISION 1. Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas.

§25.191. Transmission Service Requirements.

§25.191(a), Purpose and (b), Applicability

TXU recommended retaining the word "wholesale" in subsection (a) to clarify that these rules pertain to wholesale transmission access, but said it was appropriate to delete the phrase "at wholesale" in subsection (a)(1) because one of the purposes of wholesale open access is to facilitate competition at the wholesale and retail levels. TXU stated that §25.191(d)(4) appropriately recognizes that retail open access, including access by high-voltage retail customers, is addressed in §25.214, relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities. Similarly, Brazos recommended clarifying in subsection (c) that transmission service is wholesale transmission service, which cooperatives have an obligation to provide when necessary to serve a wholesale customer under PURA §39.203(b). Brazos added that the draft rule merely provides that transmission service allows for delivery from generation resources to serve loads.

The commission disagrees that it is necessary to draw a distinction between wholesale and retail transmission access in these rules. Therefore, the commission declines to add the term wholesale to subsection (a). The commission recognizes that it is appropriate to use the terms wholesale or retail in certain instances in these rules to clarify a specific type of customer or service. Moreover, the commission uses these terms to ensure consistency with the intent and statutory language of PURA. For example, the commission retains the term wholesale when describing the terms and conditions for wholesale transmission service at distribution voltage under §25.191(d)(2). In response to comments from Brazos, the commission finds that electric cooperatives (and MOUs) are obligated to provide wholesale transmission service, recognizing that under PURA §39.203(b) non-opt-in entities must provide this service only when necessary to serve a wholesale customer. This provision is addressed in modifications to §25.191(d)(2).

Brazos argued that the proposed rules apply to TSPs, and not DSPs, despite an apparent attempt to regulate DSPs. Brazos recommended modifying subsection (b) so that Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas) applies to DSPs only to the extent the commission has jurisdiction to regulate them. AEP replied that since §25.193 (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)) applies to DSPs, Brazos' recommendation might be appropriate, but noted that the commission already adopted substantive rules governing DSPs in Project Number 22187, *PUC Rulemaking Proceeding to*

Establish Terms and Conditions of Transmission and Distribution Utilities' Retail Distribution Service.

The commission finds that some provisions of the transmission rules apply to DSPs and, therefore, adds DSPs to the applicability section. The commission agrees with Brazos to include DSPs only to the extent that the commission has jurisdiction over DSPs. While subsection (b) states generally that the rules apply to DSPs, the commission has crafted the rule to respect the areas where it does not have jurisdiction. Where a specific provision applies to a DSP, the rule clearly states the conditions under which it applies. For example, §25.192(d)(2) applies to a DSP providing transmission service at distribution voltage and §25.193 applies to an investor-owned DSP providing service within ERCOT.

LCRA commented that subsections (b) and (c) and other sections of the rules use inconsistent terminology for the direct-current (DC) ties. LCRA suggested that they be referred to initially as "direct-current interconnections with areas outside of ERCOT" and subsequently referred to as "DC ties."

The commission agrees with LCRA and uses the suggested terms consistently throughout these rules.

§25.191(c), Nature of transmission service

TXU, joined by STEC, recommended amending §25.191(c) to recognize that transmission service is provided pursuant to commission-approved tariffs, as well as the transmission rules and ERCOT protocols. STEC stressed that the commission has sole jurisdiction over the provision of wholesale transmission service and that only the commission has the authority to set and approve rates for this service. TEC said that adding commission-approved tariffs is unnecessary and could cause confusion. TEC explained that the commission's rules take precedence over the terms and conditions in tariffs and if the commission's rules were amended there could be significant delays before new tariffs were approved by the commission. Brazos argued that, to the extent TXU's proposal to add "commission-approved tariffs" implies that cooperatives must obtain commission approval of tariffs for wholesale transmission service over distribution facilities, it is contrary to PURA and should not be adopted. Brazos said the commission has jurisdiction over cooperatives only as specified in PURA §41.004, which includes jurisdiction "to regulate wholesale transmission rates, and service, including terms of access, to the extent provided in Subchapter A, Chapter 35" and to establish terms and conditions, but not rates, for open access to distribution facilities for cooperatives providing customer choice, as provided in PURA §39.203. Brazos added that PURA §39.203 is applicable only to an MOU or cooperative that is offering choice. Brazos recognized, however, that §39.203(b) requires a cooperative that has not opted for customer choice to provide wholesale transmission service at distribution voltage, when necessary to serve a wholesale customer. AEP said the transmission service within ERCOT must also conform to FERC requirements for TSPs subject to FERC jurisdiction.

The commission agrees with TXU, STEC, and AEP that transmission service shall be provided in accordance with applicable Federal Energy Regulatory Commission (FERC) requirements and with commission-approved tariffs. The commission understands TEC's concern that tariffs may lag behind rule changes, but does not view this as rationale for excluding this language in the rule. Moreover, the commission disagrees with Brazos that requiring cooperatives to file tariffs for approval by the commission for wholesale transmission service over distribution facilities is contrary to PURA. PURA §39.203 specifically states that non-opt-in cooperatives and MOUs are required to provide wholesale transmission service over distribution facilities when necessary to serve a wholesale customer and subjects the provision of wholesale transmission service to Chapter 35, Subchapter A. Correspondingly, the definition of transmission service in PURA §31.002 includes transmission service over distribution facilities. Because wholesale transmission service at distribution voltage is designated as a wholesale service and is included in the PURA definition of transmission service, the commission has sole jurisdiction over the rates, terms of access, and conditions for such service within ERCOT, pursuant to PURA Chapter 35, Subchapter A. Moreover, PURA §41.055 specifically excludes wholesale transmission rates, terms, and conditions set by the commission from an electric cooperative's jurisdiction. Therefore, the commission agrees with STEC that it has sole jurisdiction over wholesale transmission service, rates, and access within ERCOT. The commission amends subsection (c) to clarify that transmission service must be provided in accordance with Division 1 of this subchapter, ERCOT protocols, commission-approved tariffs and, as applicable, FERC requirements.

Garland/Denton, Greenville, and TMPA suggested retaining references in previous subsection (c)(1) and (2) to planned and unplanned transmission service until there is a single control area.

As discussed above, the commission is adopting a transition provision in §25.200 to deal with this issue.

§25.191(d), Obligation to provide transmission service

TEC recommended modifying subsection (d)(2) and its subparts to reflect that TSPs are not obligated to provide access to or service over their distribution facilities to a transmission service customer if they are non-opt-in cooperatives or MOUs and do not provide wholesale distribution service. According to TEC, electric cooperatives that serve only their members are not obligated to provide open-access distribution service, nor are their distribution services subject to commission jurisdiction.

As stated previously, the commission finds that the obligation to provide wholesale transmission service extends to TSPs, even if the TSP's interconnection with the transmission service customer is through distribution, rather than transmission facilities. Notwithstanding, the commission adds language from PURA §39.203(b) to subsection (d)(2) to clarify that an electric cooperative and MOU that does not opt for competition is required to provide this service, but only when necessary to serve a wholesale customer.

According to the electric cooperatives and MOUs, subsection (d)(2)(B) could lead to unintended retail competition in areas that do not opt-into competition. Brazos, Brownsville, Cap Rock, Garland/Denton, Greenville, San Antonio, STEC, and TEC commented that this provision could allow a "partial switchover" in violation of PURA §39.203(h), which requires a total switchover from one DSP to another by disconnecting the facilities of one retail electric utility and connecting to the facilities of another. Additionally, Austin, Brazos, Garland/Denton, Greenville, San Antonio, and Tex-La stated that subsection (d)(2)(B) could inappropriately permit retail wheeling by allowing a neighboring utility to route through the distribution system of a non-opt-in cooperative or MOU to provide electric service to that utility's retail customer. They noted that this energy transfer should not be permissible, because it is at the retail level and, thus, not within the commission's jurisdiction over wholesale access. San Antonio and Austin added that this could require expensive upgrades to the distribution system of the non-opt-in entity. Moreover, San Antonio claimed this provision was a "hold over" from the pre-Senate Bill 7 rule, and should be removed.

STEC and TEC recommended including language from PURA §39.203(h) to clarify that this situation is not allowed unless the retail customer first disconnects its facilities from the first certificated retail electric utility. TXU agreed that STEC's proposal would provide a balanced solution. TXU cautioned against modifying subsection (d)(2)(B) and (C), in response to comments by some cooperatives and MOUs, in a way that would inadvertently restrict the ability of TSPs and DSPs to gain access to the wires of cooperatives and MOUs for the purpose of making utility-to-utility connections.

In view of the changes to subsection (d)(2) discussed above, regarding the conditions for which non-opt-in entities are required to provide wholesale transmission service at distribution voltage, the commission finds that no further change to subsection (d)(2)(B) addressing partial switchovers is needed, except to clarify that service provided under this subsection must be in accordance with PURA §39.203(h). Moreover, the commission amends subsection (c) to clarify that the rules in Division 1 of this subchapter do not require an MOU or electric cooperative that has not opted for customer choice to provide transmission service to a REP or retail customer in connection with the retail sale of electricity in its exclusive service area.

AEP suggested clarifying subsection (d)(2)(B) by replacing TSP with transmission service customer, because a TSP will not normally have the right to serve retail customers. TXU recommended that the term electric utility be retained instead of TSP in subsection (d)(2)(B), to ensure that a DSP who might not be a TSP or a river authority would have access to the distribution facilities of a TSP or DSP. Garland/Denton and Greenville disputed AEP's and TXU's suggestions because such modifications would permit transmission service customers to use the distribution lines of a non-opt-in entity to serve retail customers in violation of PURA. TEC suggested that the right to receive service under this subsection should not be limited to TSPs, but should apply to electric utilities, cooperatives, and MOUs.

The commission agrees with AEP that a transmission service customer, not another TSP, would have the right to provide retail electric service. Therefore, the commission amends subsection (d)(2)(B) to use the term transmission service customer instead of TSP to more appropriately translate the existing rule provision into the new market design. With the change recommended by AEP, the changes proposed by TXU and TEC are unnecessary.

In regard to subsection (d)(2)(C), AEP, STEC, and TXU commented that both DSPs and TSPs should be required to file a tariff for distribution-level transmission service. AEP said other parts of this subsection make it clear that TSPs and DSPs have the obligation to provide such service. STEC commented that the commission has jurisdiction over both tariffs – the wholesale transmission postage stamp rate and the rate charged for providing wholesale transmission at distribution voltage.

Most of the comments from the MOUs and cooperatives recommended eliminating or modifying subsection (d)(2)(C). Austin, Brazos, LCRA, TEC, and Tex-La recommended excluding MOUs and/or cooperatives from this requirement. Austin and San Antonio explained that cooperatives and MOUs that do not opt-in to competition will continue to provide distribution services on a bundled basis, which is not subject to commission tariff jurisdiction. They also said that those MOUs and cooperatives that offer retail competition are required to provide distribution *access* service, governed by the terms and conditions rule (Project Number 22187), not by this rule. Brazos, TEC, and Tex-La emphasized that the commission has no authority to require a cooperative that does not opt-in to competition to file such a tariff. Brazos and TEC also stated that this provision exceeds the commission's jurisdiction as it relates to cooperatives not owning transmission facilities. TEC pointed out that in Docket Number 23586, *Application of Brazos Electric Power Cooperative, Inc. for Withdrawal of Tariffs Except Those Concerning Wholesale Transmission Rates as a Result of Senate Bill 7*, the commission approved withdrawal of Brazos' wholesale distribution tariffs. Finally, Cap Rock, Garland/Denton, and Greenville said this provision was unnecessary unless another utility has a wholesale power delivery point on the distribution system.

TXU, STEC, and AEP disagreed with the parties that suggested that a DSP should not have to file a tariff for distribution-level wholesale transmission service. AEP stated that Austin's claim that the commission lacks jurisdiction is not supportable and would frustrate the commission's attempts to ensure competitive open access transmission service. TXU asserted that the commission clearly has the authority under Chapter 35 of PURA to regulate wholesale access to distribution facilities. TXU added that objections to the tariff based on opt-in or opt-out status are irrelevant. According to TXU, there is no basis for disparate treatment of investor-owned utilities and cooperatives and MOUs in the area of wholesale access. Similarly, STEC emphasized that the commission has sole jurisdiction over the provision of wholesale transmission service whether provided at transmission or distribution voltage. STEC did, however, support the recommendation by others that the tariff be filed only if a DSP is currently providing wholesale transmission service to an eligible transmission service customer or is requested to provide such service. Cap Rock, Garland/Denton, and Greenville suggested the tariff be filed within 30 days of the service request. TXU disagreed, arguing that waiting until a service request is made is simply a "recipe for delayed access." Numerous parties recommended amending the definition of DSP in §25.5(20) to distinguish between those entities that do and do not opt-in to competition.

For reasons stated above, the commission finds that requiring a DSP – even if it is an MOU or cooperative that does not offer customer choice – to file a tariff for wholesale transmission service at distribution voltage is not contrary to PURA. The commission recognizes, however, that the tariff would apply to non-opt-in entities only in the context of providing such service to a wholesale customer. Since there may be many DSPs that do not provide wholesale transmission service at distribution voltage, the commission finds that the tariff filing requirement should apply only to a DSP that is currently providing this service (i.e., on the effective date of this rule and thereafter) or within 30 days after a valid request for this service. Again, for non-opt-in entities, a valid request for this service would need to be from a wholesale customer. A DSP that once provided this service and has a tariff on file with the commission may discontinue its tariff if it no longer provides this service, subject to the requirement to file a tariff within 30 days after a request for this service. The commission amends the rule accordingly.

In regard to subsection (d)(4), Garland/Denton, Greenville, and TMPA suggested clarifying that the requirement for TSPs to serve retail customers not apply to entities that do not opt for competition. In addition, San Antonio noted that prior to retail competition no interaction between separate DSPs and TSPs with respect to retail customers shall exist and, therefore, this subsection should only apply to those MOUs and cooperatives that opt into competition. Brownsville commented that the commission does not have authority to require TSPs to serve retail customers because PURA Chapter 35 only requires open access for wholesale transmission service. Reliant recommended that subsection (d)(4) limit the requirement for TSPs to interconnect retail customers to those that request and are eligible for transmission voltage service. In subsection (d)(4), TXU suggested adding the word "retail" before delivery service in the reference to the standard terms and conditions for delivery service under §25.214.

The commission finds that subsection (d)(4) is unnecessary in the proposed rule. The terms and conditions of retail delivery service are addressed under §25.214 and §25.215 of this title. Therefore, the commission deletes subsection (d)(4).

§25.192. Transmission Service Rates.

§25.192(a), Tariffs

Greenville, Cap Rock, TMPA and Garland/Denton said the proposed revision to §25.192(a) could preclude non-DSP entities from paying for transmission service; these parties suggested replacing DSPs with "all eligible transmission customers receiving transmission services at transmission or distribution" level voltages. TXU proposed "transmission service customers." However, STEC said that if such a change were made, the rule must also make clear that for billing purposes it is only DSPs and entities scheduling the export of power from ERCOT that pay the charges. TEC said §25.192(a) did not clearly address transmission service for retail customers who are served by a competitive retailer and who take service at transmission voltage. TEC said these customers would not be served by a DSP, and suggested expanding these subsections so that the tariffs also apply to transmission delivery points for end-use customers served by competitive retailers. AEP disagreed with TEC and said that retail customers taking service at transmission voltage are still customers of a DSP, and that in fact transmission voltage was one of the six DSP customer classes established by Order Number 40 in Docket Number 22344, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Subst. R. 25.344*.

The commission notes the points made by STEC and AEP concerning its orders in Docket Number 22344. The commission contemplated that TSPs will bill DSPs, and that DSPs in turn will bill REPs a combined transmission and distribution charge based on the consumption of the REPs' customers. No one other than a DSP will be buying transmission service from a TSP within ERCOT, with the exception of entities scheduling exports from ERCOT over a direct-current interconnection (DC tie). Retail customers who require delivery service at transmission-level voltage within ERCOT will purchase the service from a REP that is served by a DSP, or from a NOIE that is its own DSP. Such customers compose one of the six distribution customer classes established in Order Number 40 in Docket Number 22344. Consequently, the commission declines to make the changes proposed by the parties.

§25.192(b), Charges for transmission service delivered within ERCOT

San Antonio, Reliant, TXU, and AEP suggested deleting references to weekly, daily and hourly transmission service rates in §25.192(b)(1). They said the rule should instead deal with annual transmission rates because they will be based on annual transmission costs, and that these annual rates should be divided into 12 equal monthly amounts. TXU added that it is the annual charge, not a rate, that would be converted. TIEC agreed that transmission rates should be set on an annual basis, but noted that 12 equal monthly billings would add to DSPs' working capital requirement. TIEC said that DSPs will be collecting revenues from REPs based on actual usage, which fluctuates seasonally, and that the mismatch between cash inflow and cash outflow may unnecessarily burden DSPs.

The commission agrees with parties and deletes references to weekly, daily, and hourly rates in §25.192(b). The commission acknowledges TIEC's concern that even monthly billing may add to DSPs' working capital requirement, but finds that adjusting monthly rates according to seasonal variations in the DSP's load would be too cumbersome. The commission declines to make the change suggested by TIEC; the monthly transmission rate shall remain one-twelfth the annual rate, without any seasonal adjustment. However, the commission would not object if a TSP and a DSP were to agree on a seasonal payment schedule based on a constant monthly rate, as long as the TSP does not give preferential treatment to any DSP.

§25.192(c), Transmission cost of service

Reliant said transmission cost of service (TCOS) defined in the introductory language of subsection (c) should include amounts that have been functionalized to the transmission function. LCRA said that all parts of a DC tie, including portions that operate below 60 kV, should be included in TCOS because those components are integral to the operation of the transmission system at 60 kV or higher, and recommended expanding the language of subsection (c)(1)(C).

The commission accepts these changes proposed by Reliant and LCRA.

TXU said §25.192(c)(1)(D) does not need to include capacitors and other reactive devices that operate at 60 kilovolts, as these are already included in the definition of transmission system under §25.5(82). TXU said "60 kilovolts or below" should be replaced with "below 60 kilovolts." STEC added that this paragraph should comport with Docket Number 15840, *Regional Transmission Proceeding to Establish Statewide Load Flow Pursuant to Subst. R. 23.67*, which permits capacitors to be included in the transmission cost of service if (a) the capacitor is located in a distribution substation, (b) the load at the substation has a power factor in excess of 0.95 without the capacitors, and (c) the capacitors are controlled by an operator or automatically switched in response to transmission voltage. Greenville said the 0.95 power factor should be measured on the low side without capacitors, or on the high side with capacitors.

TXU, STEC and Greenville are correct. The commission ruled in Docket Number 15840 that capacitors can qualify as transmission facilities if they meet the criteria listed in the existing §25.192(c)(1)(D). The 0.95 power factor of the substation load should be measured on the distribution side (less than 60 kV) of the substation without the capacitors. Capacitors installed on the transmission voltage side (60 kV or above) would qualify as transmission facilities even in the absence of §25.192(c)(1)(D). The intent of the decision in Docket Number 15840 was to make it possible to use capacitors in a distribution substation as a source of transmission reactive power without requiring the devices to be connected to transmission voltage. The commission amends §25.192(c)(1)(D) accordingly.

Brownsville, Greenville and TEC were concerned that "reactive devices" as used in §25.192(c)(1) was too vague. In particular, TEC was concerned that the term could be interpreted as including certain generating facilities, which TEC said should be expressly excluded in this subsection. Austin suggested that the power factor measurement be done at the summer peak. LCRA recommended adding "and other reactive devices" to all references to "capacitors" in this subsection. Reliant agreed with LCRA and said the commission should not attempt a more specific definition for reactive devices. Reliant suggested adding a provision to subsection (c)(1) that explicitly says, "reactive devices do not include generating facilities," which during the APA hearing TEC said was a good solution. STEC commented that concerns about reactive devices could be addressed by identifying all such devices in the utility's transmission cost of service proceeding so that intervenors could scrutinize them.

The commission finds that reactive devices support the transmission functions, and, thus, are appropriately included in TCOS. Whether any particular type of equipment serves as a reactive device is a factual matter to be decided in an individual rate proceeding. A definitive list need not and cannot be enumerated in this rule, other than to exclude generation facilities. The commission accepts LCRA's proposed change and Reliant's proposed language to explicitly exclude generation facilities from consideration as reactive devices.

San Antonio agreed with the recognition of the cash flow method as an alternative basis for calculating return as well as other elements of the revenue requirement in paragraph (2).

The commission concludes that this rule does not present a complete list of all alternative rate-setting methodologies available to MOUs and cooperatives. The appropriateness of any methodology that is not specifically authorized in the rule is best determined in each utility's TCOS proceeding.

§25.192(d), Billing units

Regarding the calculation of billing units, ERCOT suggested adding a clause to §25.192(d) stating that ERCOT would calculate the average coincident peak demand for the months of June, July, August and September (4CP) for each DSP "or DSP's agent for transmission service billing purposes, as appropriate." ERCOT noted that average 4CP demand is sometimes aggregated by the agent, therefore in some cases ERCOT may not have a 4CP demand for an individual DSP.

The commission accepts ERCOT's suggestion to recognize, for billing purposes, that an agent may represent a DSP.

TXU said it was no longer necessary for the commission to approve the average 4CP demand for each DSP. TXU agreed with the December 1 deadline, but said it would be sufficient for ERCOT to post the 4CP demands on its web site and that annual netting orders from the commission were not necessary. TXU argued that disputes regarding the published peaks could be handled through ERCOT's ADR procedures and that, if a DSP could demonstrate a known and measurable change in its demand, ERCOT should make the change and reflect it in the 4CP billing demands posted on the ERCOT web site. Disagreeing with TXU, ERCOT said it is not equipped to evaluate or adjudicate known and measurable changes to the 4CP, and lacked the authority to determine the reasonableness of metering information it obtained. ERCOT said the commission should continue to approve annual netting orders.

The commission agrees with ERCOT and rejects TXU's suggestion to discontinue commission approval of average 4CP demand for DSPs.

San Antonio and Nucor asked the commission to state in the rule that ERCOT would use 1-hour demand intervals, and not give ERCOT discretion to use 15-minute demand intervals to determine the 4CP demands.

In view of the use of 15-minute intervals in ERCOT energy markets, the commission finds no compelling reason to require the continued use of an hourly demand interval to determine 4CP demand.

§25.192(e), Transmission rates for exports from ERCOT, and (f), Transmission revenue

Regarding subsection (e), Reliant said transmission exports from ERCOT should be billed on an hourly basis, and that monthly, weekly and daily rates are not necessary. TXU added that transmission service in ERCOT is not differentiated based on on-peak or off-peak periods, making it unnecessary to create such a differentiation for export services. TXU and Reliant proposed simply prorating the annual access charge, which would make it mathematically impossible for actual charges to exceed the annual access charge. They also suggested eliminating subsection (e)(2) because it duplicates subsection (e)(1). TEC said charges should apply to capacity that is reserved but not used, as the DC ties are capacity constrained. TEC also proposed expanding the pricing method contained in amended §25.192(e)(3) as proposed to differentiate for peak daily (weekday) and hourly (6 a.m. to 10 p.m.) use. In its reply comments, however, AEP said the detail proposed by TEC was unnecessary. AEP said its present tariff on file with FERC caps total hourly charges for any day to the applicable daily rate times the highest amount of service reserved during that day; weekly charges are similarly structured. AEP said the approach reflected in its tariff meets the intent of this proposed subsection. Reliant also proposed deleting language from §25.192(e) dealing with the ERCOT administrative fee, saying those costs are correctly addressed in the subsection addressing ERCOT and its functions. TEC also said that all revenues from ERCOT exports should be applied to the recipients' TCOS regardless of how it is charged, and not limit the application to whether or not the charges are in accordance with subsection (e) as stated in the amended subsection (f). In the APA hearing, Reliant noted that its main concern was the collection of proper revenue. Responding to TEC, Reliant said that if exports were excluded from the 4CP calculation, then it would be appropriate to credit revenues from transmission exports against the TSP's revenue requirement. Both Reliant and TEC cited the uncertainty over whether exports would be included as load in the ERCOT 4CP.

While the export pricing mechanism proposed by Reliant and TXU has the virtue of simplicity, it does not correspond to the peak pricing mechanism used for transmission service within ERCOT. The commission concludes that continuing a pricing mechanism that results in higher charges for peak use is appropriate. TEC's suggestion to charge for reservations of capacity rather than use of capacity are not adopted. The commission needs additional information about the use of the DC ties to evaluate whether there is a problem of capacity going unused and whether TEC's suggestion is an appropriate remedy. Finally, the daily peak pricing proposal from TEC is not adopted because of the complexity it would introduce.

§25.192(g), Revision of transmission rates

TIEC said the timing of the interim rate changes contemplated under subsection (g) could lead to unstable rates if TSPs updated their invested capital at various times during the year and if DSPs adjust their transmission cost recovery factors (TCRFs) at various times during the year. TIEC suggested either (a) allowing TSP rate changes to be passed through only once per year, or (b) allowing DSPs to change their cost recovery factors only once per year. TIEC noted that Order Number 42 in Docket Number 22344 acknowledged that the TCRF "may increase risk for the distribution company" and thus a higher return on equity (ROE) was appropriate.

In view of the significant investments that are being made in new transmission facilities, it is not appropriate to restrict a TSPs' ability to update its rates for new capital investments beyond what is provided in the rule, so the commission declines to make the changes requested by TIEC. However, addressing this same concern, the commission adopts provisions in new §25.193 to limit to twice per year the number of times DSPs will be permitted to change the transmission cost recovery factor.

The commission also notes its decision in Docket Number 22350, *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and*

Public Utility Commission Subst. R. §25.344, and Docket Number 22355, *Application of HL&P Energy Incorporated for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Subst. R. §25.344*. The utilities in these two dockets are authorized to update their transmission plant in service more frequently than once per year during 2002 and 2003, whenever projects connecting new merchant generators to the transmission grid are completed and put into service. Nothing in these rules as adopted affects the commission's decision in those two dockets.

LCRA sought clarification on how transmission rates would be updated for non-IOUs that do not use the traditional rate of return method for calculating return. LCRA recommended adding to subsection (g)(1) "A municipal utility, river authority or electric cooperative may include the appropriate return elements related to the facilities using the methods allowed by §25.192(c)(2) or (3)." STEC said subsection (g) should be amended to state that it applies only to investor-owned DSPs. Regarding the requirement of §25.192(g)(5) that TSPs file reports on transmission costs and revenues, San Antonio and STEC noted that the commission has not yet adopted monitoring guidelines for investor-owned utilities, as is the case for non-IOUs. They said reports should be required specifically for IOUs for use in 2003.

The purpose of §25.192(g)(1) is to specify the basis for an interim update of transmission rates, which is change in invested capital. The commission is receptive to adopting procedures that would allow non-IOU transmission owners to update their rates for the same reason. Additional information is needed on how this could be done, and the commission declines to amend the rule now. In addition, it is the commission's intent that monitoring guidelines will be available for all TSPs so that they may file revenue and cost reports in 2003.

§25.193. Distribution Service Provider Transmission Cost Recovery Factors (TCRF).

Proposed §25.193(a), Application

TXU commented that because the billing model provides for all of the DSPs' billings for retail transmission charges to be the REPs, the reference to "other customers of the distribution system" is unnecessary, could cause confusion, and should be eliminated.

The commission is not persuaded that "other customers of the distribution system" will cause confusion and retains the language because DSPs will be serving retail customers directly where retail competition has not been introduced and indirectly through REPs where competition has been introduced.

Proposed §25.193(b), TCRF authorized

TIEC commented that §25.192(g)(4) and §25.193(b) provide that the DSP may recover any changes in the transmission rates that were included in its cost of service through a TCRF. TIEC felt it is problematic to allow the TSPs to update their transmission investment at any time, pass the change immediately on to the DSPs, and then allow the DSPs to immediately change their TCRFs. TIEC stated that there is no requirement that the changes in the TSPs' rates be passed through to the DSP simultaneously and argued that changes in the various TSPs' rates would occur throughout the year, which would create a situation in which a DSP's TCRF could also change constantly as various TSPs change their rates. TIEC suggested such a process would lead to unstable rates and difficulties for REPs trying to provide pricing stability and for customers trying to compare REP offers. AEP commented that it is important to remember that the TCRF only captures incremental transmission costs and that the vast majority of transmission costs are not recovered through the TCRF, but are instead recovered through base rates.

TIEC argued that a situation with a continuously changing DSP TCRF was inconsistent with the commission's decision in Order Number 40 of Docket Number 23444. TIEC asserted that the approved staff proposal was to use a TCRF that only changed annually, not multiple times during a year, and that the commission exhibited a strong preference in the hearing on customer classes and rate design that the transmission rate to the REPs not change continually throughout the year.

AEP argued that TIEC's understanding of staff's proposed TCRF is incorrect because the staff proposal spoke to a TCRF that allows timely recovery by DSPs of the costs imposed by TSPs, which is consistent with the commission's determination that the DSPs should act as billing agents for the TSPs. TXU argued that TIEC's warning of constantly changing rates are highly speculative and not supported. TXU argued that since 1996, transmission cost of service cases have not been frequent and saw no reason to believe that that will change with unbundling.

TIEC proposed either that a TSP's rates change only once a year or that a DSP change its TCRF only once a year, perhaps on January 1 of each year. TIEC added that the commission considered these issues when it set the ROE for transmission and distribution utilities in Order Number 42 of Docket Number 22344 and argued that the commission noted in Order Number 42 that an increase in the ROE for the utilities was appropriate because the TCRF "may increase risk for the distribution company." TIEC suggested the reason for the increased ROE is due to the TCRF proposal adopted in Docket Number 22344, which allowed changes in the TCRF only on an annual basis.

TXU argued that the commission did not limit DSPs to changing their TCRFs annually when it approved the TCRF concept in Order Number 40 in Docket Number 22344. TXU further argued that the wholesale transmission rates will not be changing frequently so there is no basis for imposing a limit in this rule on the DSPs' ability to change their TCRFs when those wholesale transmission rate changes do occur. AEP disagreed with TIEC's proposal to allow the DSP to change its TCRF only once a year while the transmission costs the DSP is responsible for billing may change much more frequently. AEP said that the DSPs proposed in Docket Number 22344 to be allowed compensation for their risk of undercollection by allowing true-ups of transmission cost recovery, but that the commission rejected that approach, opting instead for a return adjustment. AEP further argued that the issue of risk associated with collecting what is billed is different from the accurate and timely billing of costs.

Finally, TIEC noted that its proposed solutions are consistent with Reliant's initial proposal in this project, which stated that all transmission service providers that file under §25.293 in a calendar year be required to file on September 1.

The commission notes that the issue of TCRF was addressed in Docket Number 22344 where the commission recognized that in addition to fluctuations in wholesale transmission costs, a DSP is exposed to the risk of a retail provider defaulting on its payments. To address a DSP's risk of under collection and default from REPs, the commission added 50 basis points to ERCOT DSPs' return on equity. The TCRF under §23.193 of this title is intended to allow the rate to respond to commission approved changes in wholesale transmission costs that are not reflected in the DSP rate.

The commission agrees with TIEC that there is a potential problem with the frequency of changes in the TCRF. The commission recognizes a situation in which a DSP's TCRF could change constantly as various TSPs change their rates, could lead to unstable rates and difficulties for REPs trying to provide pricing stability and for customers trying to compare REP offers. The commission concludes that an appropriate balance of the competing interests is to allow the TSPs to revise their transmission rates under the expedited procedures no more than once a year. The commission does not prescribe particular dates on which these changes may be made. DSPs may change their TCRF twice a year on March 1 and September 1 of each year. The commission recognizes that allowing DSPs to change their TCRF only once per year might impose financial burdens on them, for which the commission provided an enhanced rate of return. On the other hand, allowing DSPs to immediately pass through changes in TCRFs could lead to unstable prices and difficulties for REPs trying to provide pricing stability and for customers trying to compare REP offers.

AEP was concerned that the subsection (b) language that a distribution service provider "may be allowed to" include a TCRF clause within its tariff suggests there may be instances in which a DSP may not be allowed to include a TCRF within its tariff, contrary to the notion that the TCRF would be available to all DSPs that are subject to the rule. AEP suggested that "may" be changed to "shall" in the first sentence of subsection (b), and TXU agreed in the interest of removing any ambiguity as to whether a DSP is allowed to include a TCRF within its tariff.

The commission agrees with AEP and TXU and adjusts the language of subsection (b) to remove any ambiguity as to whether a DSP is allowed to include a TCRF within its tariff.

AEP noted that the second sentence of subsection (b) provides that the terms and conditions of the TCRF clause shall be approved by an order of the commission, and asked for clarification of the second sentence with regard to the venue, timing, or content of the order mentioned.

For clarification purposes, the TCRF compliance tariffs will need to be filed within 30 days of the approval of the rule. Clarification language is added.

Proposed §25.193(c), TCRF Formula

AEP commented on the definition of load share (LS) used in the TCRF formula, noting that it is based on the DSP's load share of the new ERCOT transmission costs, given the 4CP information used to develop a TSP's new wholesale transmission rate. AEP noted that, since various TSPs will be developing new wholesale transmission rates at various times throughout the year, the definition of LS would require the tracking of multiple load share assignments in each year, which AEP felt is a cumbersome and unduly burdensome process. AEP also noted that §25.192(d) states that the DSP's LS will be determined on an annual basis and updated in December. AEP suggested the definition of LS be changed.

TXU disagreed with AEP's suggested change to the definition of LS in the TCRF formula. TXU argued that in the TCRF formula, LS is the DSP's load share from the same test year that the TSP used to develop its new wholesale transmission rate (NWTR). TIEC argued that AEP's recommendation is based on an assumption that there would be multiple load share assignments each year, which would necessitate changing the LS several times in a year and making several forecasts of projected billing determinants. TIEC disagreed with this assumption and opposes AEP's proposal. TIEC further commented that if the commission adopts Reliant's proposed clarification that transmission rate setting is an annual process, then this would satisfy AEP's concerns and no other changes are necessary. However, TIEC argued that in no event should the TCRF be set using out-of-date billing determinants. TIEC added that these rates are based on projected costs and projected loads, and further argued that by using historical billing determinants to develop a TCRF, a DSP that experiences load growth would set a per unit TCRF that is higher than is necessary to provide an opportunity to recover its transmission costs.

The commission notes that since the DSPs will be allowed to pass through changes in the TCRF only twice a year, AEP's concerns are mitigated. As discussed below, the commission has changed the TCRF formula to eliminate a potential error in the ratio of allocated costs and billing determinants so that the DSP's load based on 4CP information is used instead of the DSP's load share. Therefore, TXU's concerns are also mitigated. The commission acknowledges TIEC's concern of out-of-date billing determinants causing projected costs to be recovered over fewer billing determinants. The class allocator will be the allocator approved by the commission to allocate the transmission revenue requirement among classes in the DSP's last rate case unless otherwise ordered by the commission, and the billing determinant will be each class' annual billing determinant for the previous calendar year.

AEP and Brownsville commented on the definition of billing determinants (BD) used in the TCRF formula. AEP noted that the definition of BD requires the use of projected annual billing determinants for the same period as the new wholesale transmission cost charge which would require DSPs to forecast, develop, and maintain records of new class billing determinants each time any TSP secures a change in its wholesale transmission costs. Given the multiple number of TSPs and their ability to request changes in their transmission costs at any time throughout the year, AEP recommended that DSPs be allowed to use the same billing determinants in assignment of the incremental TCRF charges that they used in their transmission use of system charges. AEP provided revised language for the definition of BD.

The commission notes that since the DSPs will only be allowed to pass through changes in the TCRF twice a year, AEP's and Brownsville's concern is addressed and no further changes are necessary.

Brownsville suggested that there was an inherent inconsistency between the way that the BD in the denominator is determined and the way that the class allocator (ALLOC) in the numerator is determined because ALLOC is the class allocator used in the company's last rate case while the BD is a projection of billing determinants for the class. Brownsville argued that there was a problem with using the "old" allocator along with the "new" BD allocator, which may result in a misallocation of TCRF charges among the classes. Brownsville suggested that the ALLOC should be an updated class allocation factor because if the BD changes, there is no reason to assume that the allocator would remain as it was in the last rate case.

The commission notes that since the definitions of ALLOC and BD have been revised, Brownsville's concern is addressed and no further changes are necessary.

TXU and TIEC commented on the calculation of the TCRF formula. TXU felt that the purpose of the TCRF approved by the commission in Order Number 40 in Docket Number 22344 is to provide the DSP with a mechanism to recover from REPs the additional wholesale transmission charges that the DSP will be billed by TSPs that revise their TCOS, above the wholesale transmission charges that the DSP is recovering in the base retail transmission charges previously approved for the DSP by the commission. TXU suggested that the TCRF was also approved to reduce the DSP's exposure to risk resulting from it being required to pay transmission charges to the TSPs, even if the DSP does not collect from the REPs.

To reflect that intent and to accurately calculate the amount of those additional wholesale transmission charges, TXU recommended a TCRF formula that would apply the "new" wholesale transmission rate to the DSP's "new" load share and subtract from that product the amount of wholesale transmission charges that are currently being recovered through the DSP's retail transmission charges. TXU proposed that the latter amount is found by multiplying the "base" wholesale transmission rate by the DSP's "base" load share. TXU argued that the formula in the proposed rule inappropriately applies a new load share to the base wholesale transmission rate.

TIEC suggested that the proposed formula contains a potential error that needs to be corrected. TIEC commented that the terms new wholesale transmission rate (NWTR) and base wholesale transmission rate (BWTR) are defined as rates in $/kW amounts. TIEC argued that the increase in the DSP's cost would be the difference of NWTR and BWTR multiplied by the DSP's 4CP demand (and not the DSP's 4CP load share as the proposed formula appears to require) and that this increased cost should then be allocated to classes using the appropriate allocation factors. TIEC suggested the TCRF should be the ratio of the allocated costs and the projected billing determinants.

TXU argued that implementing TIEC's proposal would require a contested-case proceeding at the commission every time a DSP wanted to change its TCRF, which would be an expensive and time consuming process that would defeat the commission's goal of enabling DSPs to timely recover changes in wholesale transmission charges. TXU suggested that the difficulty in updating 4CP allocation factors on a timely basis would be further compounded by the extensive amount of time required to gather and prepare the load research data required to determine the 4CP on the non-interval data recorder (IDR) classes and of the classes which contain both IDR and non-IDR customers. TXU added that the commission has historically implemented power cost recovery factors without requiring updated allocators.

The commission agrees in part with TXU that the formula in the proposed rule inappropriately applies a new load share to the base wholesale rate. The commission also recognizes TIEC's suggestion of a potential error in the proposed formula and that the TCRF should be the ratio of the allocated costs and the billing determinants. To properly reflect incremental transmission costs to be passed through using the TCRF formula, the NWTR should be multiplied by the DSP's new load based on the 4CP information used to develop the NWTR from the previous calendar year and the BWTR should be multiplied by the DSP's load based on the 4CP information used to develop the BWTR in the DSP's last rate case.

Proposed §25.193(d), Revision of allocator

TXU, AEP, and TIEC commented on the revision of the allocator in the TCRF formula. This subsection provides the DSP the right to petition the commission for approval of the use of updated allocators. TXU felt that there is a possibility for confusion over this subsection in the future. To avoid later confusion, TXU recommended that the following sentence be added to clarify what happens if a petition is not filed: "If the distribution service provider does not petition the commission for approval to update the allocators, the allocators used in the distribution service provider's last rate case shall be used and deemed approved on a final basis." AEP also asked for clarification that DSPs are not required to update allocators because of the cumbersome and burdensome process. TIEC, on the other hand, strongly supported a requirement that the factors used to allocate transmission costs be updated annually when the new transmission rates are set. TIEC said that AEP's objection would be relieved by allowing the TCRF to be changed annually. TIEC also objected to TXU's proposal because they felt it could potentially be used to perpetuate a misallocation of transmission costs.

AEP also commented that there is a potential for refunds to any class whose TCRF using updated allocators is ultimately determined to be lower than that using the interim allocators. AEP noted that there is a significant problem with this provision because if one class was being "overcharged" on an interim basis, another class was being "undercharged", and there is no provision for surcharging the undercharged class. Since the DSP is merely acting as a billing agent for the various TSPs, AEP argued that it is inappropriate to place the risk of undercollection on the DSP. If interim allocators are to be used, AEP recommends that subsection (d) be revised to also address undercollections.

Reliant and TXU agreed with AEP that there should be a surcharge of an undercollection to any particular class if it is required to refund overcollections to classes that received a higher allocation. TIEC submitted that allowing surcharges and refunds would require more effort and complication than simply updating the customer class allocation factors.

The commission notes that the definition of allocator in the proposed rule establishes that DSPs should use allocators from their most recent rate case when applying the TCRF formula. Therefore, it is not necessary for the DSP to petition the commission for approval of the use of updated allocators. The commission concludes that the use of revised allocators is cumbersome and is removing section (d). By requiring DSPs to use the allocators from the most recent rate case and eliminating the potential for petitions and interim periods of implementation of allocators, the issue of over and/or undercollecting by class is moot.

Proposed §25.193(e), TCRF charges

TXU suggested that the TCRF in subsection (e), when applied on an annual basis to the applicable monthly billing units, might be so diluted as a result of rounding that significant amounts of aggregate revenue will never be recovered. TXU added that this result is inconsistent with the intent of the TCRF provisions of Order Number 40 in Docket Number 22344. TXU suggested that if the TCRF is calculated on an annual basis, and it recovers less than one dollar from a residential customer consuming 500 kWh per month, then the DSP may collect the entire amount in one month.

TIEC argues that if the TCRF is this small, then, TXU can choose not to implement it. TIEC added that TXU's proposed rule is unnecessary and should be rejected.

The commission concludes that if the TCRF is so small that it will be deleted as a result of rounding, the lost revenue would be inconsequential. Therefore, the commission takes no action in response to TXU's concern.

Proposed §25.193(f), Reports

TXU addressed the "estimated TCRF costs" reporting requirement in subsection (f) concerning TCRF collections, and argued that there is no need to require the reporting of estimated data, since actual data will exist. TXU suggested alternate language and further recommended that report due dates be specified in the rule, suggesting March 31 and September 30.

TIEC suggested that the reporting requirement could be amended to require a comparison between actual and forecast recoveries and billing determinants, which would allow the commission to monitor the reasonableness of the projections used to establish projected billing determinants used in setting the TCRF. TIEC further recommended that the commission require TSPs to file projections of future transmission costs. TIEC argued that these cost projections, coupled with the five-year load forecasts recommended by TXU, would provide the commission with important information about future levels of transmission rates. TIEC suggested that this information could be used to either minimize or moderate future rate changes and promote stability.

The commission agrees with TIEC that semi-annual reports containing all information required to monitor the costs recovered through the TCRF clause would provide the commission with useful information. The commission disagrees with TIEC's recommendation for TSPs to file projections of future transmission costs. The commission agrees with TXU that reports should be filed twice a year on March 31 and September 30 of each year, for the preceding six-month period ending December and June, respectively.

§25.195. Terms and Conditions for Transmission Service.

Proposed §25.195(a), Transmission service requirements

Reliant commented that in the emerging market, transmission service customers will not all be required to have interconnection agreements with the TSP, that each utility has specific guidelines and service extension tariffs to address certain requirements for interconnection, and that, therefore, the reference to the condition to obtain transmission service should be adjusted. Reliant also commented that the proposed rule should be amended to be consistent with Docket Number 22052, *Petition of the Electric Reliability Council of Texas, Inc. (ERCOT) for Approval of the Standard Generation Interconnection Agreement*, where the commission decided that "the parties to an interconnection agreement should be able to modify the standard agreement in individual cases to meet the special needs of a project, but this ability must not frustrate the goal of expeditious, non-discriminatory interconnection." TXU commented that the last sentence regarding the modification of standard agreements with commission approval, should be modified to reflect that a generator and TSP may mutually agree to modify the commission approved form agreement to address the specific facts presented by a particular generator interconnection request. FPLE agreed with Reliant, but said the flexibility for individual projects must be balanced with the need for non-discriminatory treatment of generators, including those affiliated with TSPs. FPLE argued that, therefore, the rule should also include a provision that any modification to the standard generation interconnection agreement (SGIA) for individual projects must (1) not be inconsistent with the principles underlying the SGIA as articulated by the commission in its March 29, 2000 and May 16, 2000 orders in Docket Number 22052; and (2) be filed with the commission.

The commission agrees with FPLE and modifies the rule to support modifications to the SGIA by affected parties as long as the underlying principles of the SGIA are upheld and the complete agreement is filed with the commission.

TXU commented that the first sentence of §25.195(a) should be revised to include DSPs because transmission service includes service over distribution lines provided by DSPs.

The commission finds that this change is not necessary because the definition of transmission service includes service over distribution facilities.

TEC commented that subsection (a) provides a commission-approved standard form of agreement for interconnection of new generating facilities. TEC explained that interconnections other than new generating facilities will occur, including (1) connection of new distribution substations, and (2) bulk transmission interconnections. TEC further argued that the commission has not adopted standard interconnection agreements for those types of interconnections. TEC commented that the commission should adopt a standard form of interconnection agreement applicable to the connection of new distribution substations and bulk transmission interconnections in order to facilitate their timely completion. AEP responded by supporting the development of a standard agreement for the interconnection of new generating facilities. TXU responded that standard agreements have been helpful in facilitating the interconnection process for new generators. TXU added that utility to utility interconnections have been established throughout Texas for years with very little if any controversy and none of the difficulties of the nature that prompted the development of the SGIA. In addition, TXU added that TEC did not provide any support demonstrating the need for additional forms. STEC responded that is supports TEC's recommendation, so long as such agreements provide sufficient latitude for the parties to address those conditions unique to their situation.

The commission declines to adopt TEC's proposal for additional standard interconnection agreements at this time. TEC has not established the need for such a standard agreement.

Reliant commented that the second sentence must be amended to apply to only generators and not to all transmission service customers. TXU commented that the second sentence phrase "transmission service customer" should be replaced with "power generation companies and exempt wholesale generators" because those are the only transmission service customers who will be executing a generation interconnection agreement with a TSP. Austin and Brazos supported TXU's comment.

The commission agrees with the intervenors that "transmission service customer" should be replaced with "power generation companies and exempt wholesale generators."

§25.195(b), Transmission service provider responsibilities

Austin commented that the last portions of this subsection, which require the transmission service provider to "plan, construct, operate and maintain facilities" does not make it clear that

Austin cannot construct ERCOT recommended transmission facilities until commission approval is gained. Austin suggested adding "and approved by the commission" for clarification.

The commission agrees with Austin and adopts its suggestion to clarify that TSPs are not obligated to construct ERCOT recommended transmission facilities until commission approval is granted, if such approval is required.

§25.195(c), Construction of new facilities, and Preamble Question Number 2

In its publication preamble, the commission asked the following question: How should the rules accommodate the special financing rules of utilities that use tax-exempt financing?

Austin commented that the transmission rules must be flexible for MOUs and recommended that language be added to §25.192(c)(2) and (3) for the purpose of determining the annual transmission revenue requirements for municipal utilities, river authorities, and cooperatives.

Brazos and STEC urged the commission to continue to require netting of transmission charges among TSPs so as not to jeopardize electric cooperatives' 15% non-member income requirement. Brazos and STEC point out that PURA §41.104 requires that nothing in the subtitle may impair the tax-exempt status of electric cooperatives.

The importance of the provisions of proposed §25.195(c)(2) and of the protection of its tax-exempt status for the purposes of financing power by public entities were of utmost concern to several parties. Garland/Denton, Greenville, and TMPA urged that the proposed language of §25.195(c)(2) be retained. In particular, they were concerned that the proposed rule would require partial switchovers in multiply certificated areas, which could cause a tax-exempt entity to violate sections of federal tax laws. Garland/Denton and Greenville also commented that the rule should be revised so that a utility is not required to wheel power from a distributed generation resource if it will affect the tax-exempt status of the utility.

San Antonio commented that the rules should continue to make provisions for protecting the tax-exempt status of public power entities' financing. San Antonio suggested that §25.195(c)(2) be retained and expanded to include the concept of construction as well as acquisition, and to recognize that a reasonable expectation of bond status impairment should be an appropriate basis for the requirement. San Antonio commented that §25.195(c)(1) and §25.198(d)(3) should acknowledge the possibility of a contribution in aid of construction being required.

The commission adopts San Antonio's suggested revision of §25.195(c)(2) with the exception of "or reasonably could be expected to impair" and inserts the reference to the paragraph in the second sentence of §25.195(c)(1). The commission adopts San Antonio's suggestion to add a reference to the paragraph at the beginning of §25.198(d)(3). The commission believes that these revisions to §25.195 and §25.198 adequately accommodate the special rules of the utilities that use tax-exempt financing.

LCRA suggested that §25.195(c)(1) be modified to clarify the type of protective devices that a new generator must install as a condition of receiving transmission service to be consistent with

ERCOT's SGIA. TXU responded that the language "including the interruption device" is not clear; modified language would be "capable of electrically isolating the facilities owned by the transmission service customer." TXU supported LCRA's changes with this language modification.

The commission adopts TXU's proposed modification in §25.195(c)(1).

Austin suggested that the last sentence of this paragraph should state that the TSP is responsible for the cost of installing "any other transmission system upgrades on its own transmission system that may be necessary to accommodate the requested transmission service" to make it clear that a TSP is not required to pay for facilities upgrades on another TSP's system for a specific interconnection of generation and needed transmission service.

The commission adopts Austin's proposal, clarifying that a TSP is not required to pay for facilities upgraded on another TSP's system.

Proposed deletion of existing §25.195(d), Priority for transmission service applications

Greenville, Garland/Denton, and TMPA commented that the provisions for planned and unplanned transmission services need to remain in the rule subject to implementation of the single control area, or the rule should not become effective until the single control area is operating.

The commission is addressing this matter by adopting transition provisions in §25.200.

Existing §25.195(g), Filing of contracts

Granbury commented that the provisions of existing §25.195(g), relating to the filing of contracts, should not be deleted. Granbury asserted that currently there are no approved standard interconnection agreements for interconnecting load serving distribution systems to the TSP facilities, and that the proposal should be retained to include language that the interconnection agreements are subject to commission review and approval upon request by any party to the agreement. TXU replied that it is happy to continue to make such filings if the commission wished to continue receiving them. TXU argued that even if this subsection were deleted, any DSP that believes it has a complaint against a TSP concerning interconnection issues has the right and the ability to file a complaint with the commission. TXU argued that, therefore, the language of §25.195(g) of the existing rule is unnecessary. STEC replied that it agreed with Granbury that the §25.195(g) language is necessary because abuse has occurred in this area in the past, and is likely to continue to occur in a competitive market.

The commission agrees that, to protect against abuse in the future, the provisions of the existing rule §25.195(g) should remain in the new rule. The language from the existing rule is adopted as §25.195(e).

§25.196. Functional Unbundling.

Proposed §25.196(a), Applicability

Reliant and AEP recommended language to limit the applicability of §25.196 so that electric utilities with a code of conduct and business separation plan are not subject to these provisions. However, Garland/Denton, Greenville and TEC responded that excluding IOUs from this provision does not address the problem associated with the commission's lack of authority to require cooperatives and MOUs to functionally unbundle.

The commission agrees with Reliant that §25.196 should not apply to IOUs with an approved Code of Conduct and Business Separation Plan. Therefore, the commission amends subsection (a) to clarify that §25.196 does not apply to TSPs that are required by PURA §39.051 to unbundle their generation and transmission activities and that operate under an approved code of conduct and business separation plan. The commission also deletes the language regarding river authorities, MOUs, and cooperatives in subsection (a); however, this section, as modified to remove the functional separation requirements, continues to apply to these entities if they meet the criteria specified below in the discussion regarding standards of conduct.

Proposed §25.196(b), Separation of functions (now deleted)

Austin, Brazos, Brownsville, Cap Rock, Garland/Denton, Greenville, San Antonio, STEC, TEC, and TMPA commented that the commission does not have authority to require an MOU or cooperative to unbundle its services or functions. They argued that PURA §§40.054(e), 40.055(a)(2), 41.054(e), and 41.055(2) specifically provide that: 1) the decision to unbundle resides exclusively with the governing bodies of MOUs and cooperatives, and 2) the commission has no jurisdiction to require an MOU or cooperative to unbundle its services or functions. Cap Rock, Garland/Denton, Greenville, and TMPA contended that the commission already acknowledged in the code of conduct project that the decision to unbundle lies exclusively with the MOU or cooperative, and further argued that this provision is impractical because such separation would add significant costs to small systems without intending to do so and because these systems are not large enough to affect the market.

San Antonio indicated that the standards of conduct in the existing rule that pre-date Senate Bill 7 are appropriate to ensure fair and competitive functioning of the wholesale market, but that there should not be a blanket requirement that functions of an MOU be separated. Thus, San Antonio suggested deleting the functional separation requirement in subsection (b).

TXU also acknowledged the statutory concerns raised by other parties regarding unbundling and recommended clarifying that subsection (b) applies to TSPs that are not otherwise required to unbundle by PURA §39.051. However, TXU did not understand the existing rules requirement of "functional separation" to equate to "unbundling," in contrast to other parties.

The commission agrees that requiring an MOU or cooperative to unbundle its services or functions is contrary to PURA. Since investor-owned utilities are already subject to unbundling requirements under PURA §39.051, the commission deletes proposed subsection (b) to remove the separation of functions requirement.

Proposed §25.196(c), Standards of conduct (now (b))

Brazos, Garland/Denton, Greenville, Tex-La, TEC, and TMPA recommended deletion of proposed subsection (c), pertaining to standards of conduct. According to TEC, these standards should not apply to non-opt-in cooperatives because the existing standards were adopted prior to Senate Bill 7, which authorizes the commission to establish a code of conduct that applies only to cooperatives that opt-in to competition and offer service outside their service areas. Moreover, Garland/Denton, Greenville, TMPA and TEC commented that standards of conduct are already sufficiently governed by other code of conduct rules. Brazos argued that the commission's jurisdiction over cooperatives to establish a code of conduct is also limited under PURA §39.157(e) and §41.054(b). Brazos added that PURA §41.054(d) requires the commission to make accommodation in the code of conduct for the organizational structure of electric cooperatives and mandates that the commission not prohibit an electric cooperative and any related entity from sharing officers, directors or employees. According to Brazos, this limitation is equally applicable to the provisions of proposed §25.196(c). Brazos recognized that although PURA §41.004 gives the commission jurisdiction over electric cooperatives to regulate transmission rates and services, it is only "to the extent provided in Subchapter A, Chapter 35," which does not include the right to impose standards of conduct on electric cooperatives.

San Antonio maintained, however, that an appropriately structured code of conduct is necessary under the transmission rules for the equitable functioning of the wholesale market. Nevertheless, San Antonio agreed with the concerns voiced by STEC and Brazos that such a code should not infringe upon the exclusive jurisdiction of a MOU or cooperative to determine what unbundling may be necessary to meet this objective. San Antonio was particularly concerned with subsection (c)(2), stating that it goes beyond what is necessary to foster a wholesale market in restricting communications of a TSP's employees engaged in transmission with all other employees. San Antonio said the appropriate focus of the standards is on the merchant function, which should be treated as any other market participant with regard to potential use of the TSP's transmission system. San Antonio pointed out, however, that subsection (c)(2) is too broad and would inappropriately extend beyond the transmission/merchant relationship. Citing PURA Chapter 35 and §40.005(i), STEC argued that the Legislature expressly stated that the commission – not the governing bodies of MOU or cooperatives – has sole jurisdiction over wholesale transmission rates, terms of access, and conditions except as affected by those items in PURA §40.055 and §41.055. STEC further commented that the provision in PURA Chapter 41 making only opt-in cooperatives subject to the commission's code of conduct addresses competitive retail services, not wholesale transmission. Also, TXU stated that the commission should act to the fullest extent of its authority to require that non-IOU TSPs take the actions necessary to ensure the comparability requirements of PURA Chapter 35 are satisfied for wholesale transmission service.

The commission agrees with San Antonio and STEC that certain standards of conduct are necessary in these transmission rules for the equitable functioning of the wholesale market. The commission also agrees that it is not contrary to PURA to apply these standards to TSPs that are MOUs and cooperatives, even if they do not opt-in to competition. The commission amends the standards in proposed subsection (c)(2) as proposed by San Antonio to ensure that the focus is on the merchant function, which should be treated as any other market participant regarding the potential use of the TSP's transmission system. This subsection is renumbered as (b).

However, the commission understands that these requirements may be impractical or unnecessary for TSPs with small systems. Therefore, the commission amends subsection (a) to limit applicability only to TSPs that have retail sales of total metered electric energy for the average of the three most recent calendar years that is greater than 6,000,000 megawatt hours. The commission may expand the applicability in the future to a broader set of TSPs if it determines that such provisions are necessary to prevent market abuses.

Brazos raised concerns about proposed §25.196(c)(1), which prohibits employees of a TSP who "are engaged in wholesale merchant functions" from certain actions. Brazos pointed out that, in the original transmission rulemaking, Docket Number 14045, *Rulemaking on Transmission Pricing and Access (Subst. R. 23.67 and 23.70)*, the commission held that, with regard to the power supply obligation to its members, Brazos is not providing a "merchant function" due to its long-term contractual commitments with its members.

Given the change in the applicability of this section, the commission finds it unnecessary at this time to address the exemption claimed by Brazos.

Austin commented that there was no definition of "electronic information network" used in subsection (c)(1)(C) and other subsections of the rule. In particular, Austin questioned whether the ERCOT Market Information System (MIS) qualifies as the "electronic information network."

Electronic information network refers to the FERC requirement to have a publicly available wholesale information network that provides certain types of information to market participants as well as to meet code of conduct requirements. In the new market design, the ERCOT market information system will qualify for the former. However, posting of certain information related to code of conduct would need to be posted as well. The commission finds no need to have a definition in the rule.

Austin suggested that subsection (c)(1)(D) is not needed in light of the prohibition in subsection (c)(1)(C), which states that a TSP's employees who are engaged in wholesale merchant functions shall not have preferential access to information about the TSP's transmission system that is not otherwise available. Moreover, Austin commented that the blanket prohibition in subparagraph (D) against obtaining any information, which includes non-preferential information, could be harmful if it prohibits transmission personnel from attending necessary ERCOT stakeholder meetings where they may come across such information. Austin also recommended that the information concerning transfers of persons, required by proposed subsection (c)(3), be provided to the commission rather than ERCOT since the commission is responsible for supervising such transfers.

The commission agrees with Austin that subsection (c)(1)(D) appears redundant and could inappropriately restrict sharing of information, and therefore deletes it. The commission also agrees with Austin on the reporting of information concerning the transfers of persons, and amends subsection (c)(3) accordingly.

Proposed subsection §25.196(d), New construction of generation (now deleted), and Preamble Question Number 1

In its publication preamble, the commission asked: *Should the commission eliminate proposed §25.196(d), formerly §25.196(b)(4), that limits construction of new generation by a transmission service provider's affiliate in the transmission service provider's service areas? If not, why should it be continued, and for how long?*

All commenting parties stated that proposed §25.196(d) can be deleted. Reliant, STEC, and TMPA stated that this provision is no longer necessary due to the commission's adoption of the Code of Conduct and Business Separation Plans. TXU noted that Senate Bill 7 includes a comprehensive statutory framework to protect against generation market abuses. LCRA added that the commission has adopted other protections against discriminatory behavior.

Brazos, Garland/Denton, Greenville, LCRA, TMPA, San Antonio, and STEC stated that this provision should not apply to MOUs and electric cooperatives because PURA gives exclusive jurisdiction to their governing bodies to manage and operate their utility systems, including the exercise of control over resource acquisition and any related expansion programs. TEC commented that this section effectively applies only to electric cooperatives and is beyond the commission's authority, because they are not required to unbundle under any circumstances and are required to operate under the commission's code of conduct only if they opt-in and offer service outside of their certificated areas. Austin stated that the commission does not have jurisdiction under PURA to address, let alone restrict, an MOU's construction of new generation.

Brazos commented that this subsection serves no useful purpose, creates undue confusion, and establishes barriers to construction of generation needed to relieve transmission constraints. Garland/Denton and Greenville cited recent events in California to state that limiting construction of new generation can have extremely adverse consequences.

FPLE argued that the limitation contained in this section is no longer necessary if, and only if, the commission requires all previously bundled affiliated generators to execute the SGIA and to file such agreements with the commission after adoption of the transmission rule. FPLE stated that such SGIA requirements are necessary because interconnection agreements have not previously been required between TSPs and their non-merchant generation affiliates, which places non-affiliated power generating companies, who have been required to use the SGIA prospectively since its approval by the commission, at a potential competitive disadvantage after restructuring with affiliated generators. Reliant replied, however, that this issue should not be addressed in this rulemaking because the commission has already addressed this issue of whether previously bundled affiliated generators should be required to execute the SGIA for their interconnections arrangements with affiliated TSPs. Reliant noted that in Docket Number 22052, *Petition of the Electric Reliability Council of Texas, Inc. (ERCOT) for Approval of the Standard Generation Interconnection Agreement*, the commission found that "if parties have concerns about interconnection arrangements that predate the approval of the SGIA, they may raise them in an appropriate dispute-resolution forum." TXU also replied to FPLE's comments, stating that the elimination of §25.196(d) should not be conditioned. TXU noted that FPLE's concern, that the terms and conditions of interconnection for these previously bundled generators will not otherwise be subject to commission scrutiny, is not warranted because the commission's code of conduct rules already require that all contracts between a transmission and distribution utility and its affiliates be filed with the commission, which affords an opportunity to ensure that such contracts do not give affiliated generators a competitive advantage.

STEC commented that the only limitation placed on an affiliate generator by PURA is that it may not own and control more than 20% of the installed capacity located in, or capable of being delivered to, the power region.

LCRA argued that the proposed rule appears to greatly expand on existing §25.196(b)(4) because it now applies to a TSP's service area instead of a utility's retail service area. Moreover, LCRA commented that it could never qualify for the exception provided in proposed subsection (d)(1) because this subsection requires it to structurally unbundle its generation and transmission operations but it is not required by PURA to obtain the commission's approval regarding such unbundling. LCRA recommended that, if the commission retains this provision, it should reflect that TSPs do not have service areas and that the commission does not have the authority to approve the unbundling methods used by MOUs, cooperatives, and river authorities.

The commission agrees that §25.196(d) should be deleted because it is no longer needed. The unbundling and code of conduct requirements should sufficiently address vertical market power issues for investor-owned utilities and render subsection (d) unnecessary. Moreover, the commission believes that imposition of such a prohibition on MOUs and cooperatives would be contrary to PURA.

§25.198. Initiating Transmission Service.

TXU suggested wording changes for a variety of references to reflect the fact that transmission service is a regulated service provided under commission-approved tariffs, the Substantive Rules and the commission-approved ERCOT Protocols. Specifically, TXU advocated changes to subsections (a), (b) and (c) of this section, similar to its suggested changes to §25.191(c), which are references to "commission-approved tariffs," and "commission-approved ERCOT protocols." Also, TXU recommended revising the title of subsection (c) to "Procedures for initiating transmission service." ERCOT suggested that the use of "commission-approved" as applied to the ERCOT protocols should not be used because the commission does not specifically approve most ERCOT protocol revisions, although they are subject to oversight and review by the commission. TEC and Brazos disagreed with TXU's suggestion to refer to "commission-approved tariffs." Brazos explained that the wording implies that an electric cooperative must obtain commission approval of its tariffs for wholesale transmission service over the cooperative's distribution facilities, which is contrary to PURA, and not advisable.

The commission agrees that TXU's suggested title of subsection (c) is an improvement and adopts it. The commission agrees with ERCOT that the description "commission-approved" to describe ERCOT protocols should not be used, because such language could give the impression that the commission directly approves all ERCOT protocols. However, the commission adopts the use of "commission-approved" to modify tariffs in subsections (a), (b) and (c).

§25.198(b), Condition precedent for receiving service

LCRA commented that the proposed deletion of §25.198(b)(5) might be inconsistent with retaining the power factor language in §25.192(c)(1)(D).

The commission does not see an inconsistency between the subsections, because §25.192(c)(1)(A)-(D) is a list of facilities that qualify as transmission facilities, and subsection (c)(1)(D) is a description of requirements for capacitors and other reactive devices that qualify as transmission facilities. The commission makes no changes to the proposed rule in this regard.

§25.198 (c), Procedures for initiating transmission service

ERCOT suggested that in §25.198(c)(6)(A), 60 business days be changed to 90 calendar days, stating that ERCOT required at least 90 days to perform the system security screening study. Mirant replied that it recommended 60 business days, which is equivalent to 85 calendar days, as the time frame for completion of the security screening study.

The commission agrees that 90 calendar days is a more reasonable period to complete such a study and adopts ERCOT's recommendation. Given that it is only a 5-day increase over the calendar period spanned by 60 business days, the extension should not present a burdensome delay.

§25.198(d), Facilities study

LCRA, Reliant, and TXU suggested deleting the reference to ancillary services in the introductory language to this subsection. Reliant suggested adding "good utility practice" in the last sentence of §25.198(d)(1)**,** as well as in the last sentence of §25.195(c)(1).

The commission deletes the reference to ancillary services in the introductory language of §25.198(d) and adds "good utility practice" in §25.198(d)(1), as well as in §25.195(c), to be used in the same context and meaning as it is used in §25.195(b).

San Antonio, Greenville, LCRA and TXU commented on §25.198(d)(3). San Antonio said that the language of this section is overly broad. San Antonio noted that the concept of TSP responsibility for transmission-related construction is appropriate as stated in §25.195(c)(1), and that therefore the language here should indicate that the facilities referenced belong to the TSP and acknowledge the potential necessity of protection of tax-exempt financing by referencing §25.195(c)(2). Greenville suggested clarification of the proposed amendments to apply only to new service for a new transmission service customer. LCRA recommended that the original language, which referenced the cost of a facilities study, be retained. TXU recommended that subsection (d)(3) be deleted because it refers to the responsibilities of a TSP for planning, design and construction of transmission facilities used to provide transmission service.

The commission agrees with San Antonio and incorporates its suggested language. The commission adopts the rest of subsection (d)(3) as written, finding that the language is necessary to precisely describe the TSP's responsibilities related to the costs of planning, designing, and constructing its own facilities to provide transmission service.

§25.198(h), Changes in service requests

Reliant recommended that §25.198(h) not be amended, because the existing language provides for the appropriate cost recovery for any changes in service requests. FPLE replied that §25.195(c)(1) could be expanded to include the costs of a facility study to address this concern.

The commission disagrees with Reliant and agrees with FPLE. Reliant's concerns for the recovery of costs for the studies noted in §25.198(h) are addressed by §25.195(c), which provides the means for the TSP to recover its costs incurred in planning, licensing, and construction activities in the event a TSC does not complete its new planned facilities and does not take transmission service. The commission adopts §25.198(h) as proposed.

§25.198(i), Annual load and resource information updates

In §25.198(i), TXU recommended that the annual updates of load and resource forecasts be provided to ERCOT "for the following five-year period."

The commission agrees with TXU that this subsection needs clarification as to the length of the forecasts and adopts the suggested five-year forecast period.

§25.198(j), Termination of transmission service.

Austin suggested that transmission service customers notifying the TSPs of termination of transmission service should notify ERCOT as well.

The commission agrees with Austin and amends §25.198(j) to say that a transmission service customer may terminate transmission service after providing the appropriate TSP and ERCOT with written notice of its intention to terminate.

§25.200. Load Shedding, Curtailments, and Redispatch.

Generally, TXU commented that pending changes in the ERCOT market structure and the operations of the ERCOT organization requires changes in the way these activities are currently addressed in the transmission rules. In reference to these impending changes, TXU stated that curtailments will no longer be an activity conducted by the TSP or the DSP, and references to curtailment in general should therefore be deleted from the section. ERCOT stated that the proposed amendments in §25.200 are addressed in Sections Number 5 (relating to *Dispatch*), Number 6, (relating to *Ancillary Services*) and Number 7 (relating to *Congestion Management*) of the ERCOT protocols.

ERCOT, in reply comments, disagreed with TXU's suggestion that the provisions regarding ERCOT's authority to direct "curtailment" and "redispatch" be deleted from §25.200. ERCOT stated that it is important to reflect in the transmission rules ERCOT's authority to act as necessary to address emergency conditions where reliability and safety of the ERCOT transmission network is threatened.

The commission agrees with ERCOT that it is important to reflect that ERCOT has the authority to act as necessary in emergency situations and therefore finds that TXU's suggested revision is not appropriate. However, the commission has revised §25.200(a) to reflect that curtailment and redispatch must be in accordance with the ERCOT protocols.

§25.200(b), Congestion management principles

TXU stated that congestion management is addressed in the ERCOT Protocols being approved by the commission under Docket Number 23220, *Petition of the Electric Reliability Council of Texas (ERCOT) for Approval of the ERCOT Protocols*. TXU recommended that §25.200(b) therefore be deleted. Brownsville stated that because §25.200(b) provides that ERCOT shall develop market mechanisms to manage transmission congestion, it should be amended to require that these market mechanisms be approved by the commission.

The commission recognizes that congestion management is addressed in the ERCOT protocols, but finds that this needs to be reflected in the rule, and has revised the rule language accordingly. The commission is changing the definition of the ERCOT protocols that reflects the approval process for such protocols in §25.5, relating to Definitions. Therefore, the proposed change by Brownsville is no longer needed.

§25.200(c), Transmission constraints

In reference to restoration of service under §25.200(c)(1), ERCOT stated that operational conditions may call for caution in restoration of service if such restoration creates risks to safety of personnel, equipment or reliability. ERCOT further stated that Section 5 of the ERCOT protocols relies heavily on the TSPs in selecting loads to be shed during emergency conditions, and that this will be largely market driven rather than at ERCOT's direction. Therefore, ERCOT recommended that the language in §25.200(c)(1) be amended to include a reasonableness element.

The commission agrees with ERCOT that operational conditions may call for caution in the restoration of service and that ERCOT will rely heavily on the TSPs for such activities. The commission accepts the reasonableness element proposed by ERCOT and changes the rule accordingly.

In reference to §25.200(c)(3), ERCOT stated that it may not be possible for it to determine with great accuracy what actions are "least cost" and what actions will result in "equal treatment," when the priority for ERCOT is to stabilize the system and restore service in a safe and orderly manner. In addition, according to ERCOT, it relies on the TSP to curtail load with little control by ERCOT, and this requirement may lead to needless disputes over what in hindsight may have been the most cost-effective and non-discriminatory deployment of resources in an emergency situation. Therefore, ERCOT recommended that subsection (c)(3) be amended to include a reasonableness element. TXU stated that neither curtailment nor redispatch appear as concepts recognized by the ERCOT protocols. Therefore, TXU recommended the deletion of §25.200(c).

FPLE responded that ERCOT's general obligation to redispatch on a least cost non-discriminatory basis and to provide equal treatment among TSCs is unqualified in non-emergency situations. FPLE further stated that it did not object to a reasonableness standard for redispatch in true emergency situation, but stated that the language proposed by ERCOT is overly broad and is not limited to emergency situations, and should therefore be rejected.

The commission agrees with ERCOT that it may not be possible for ERCOT to determine with great accuracy what actions are "least cost" and what actions will result in "equal treatment", when the priority for ERCOT is to stabilize the system and restore service in a safe and orderly manner. The commission also agrees with FPLE that the reasonableness standard proposed by ERCOT is overly broad and may easily become standard operating procedure. The commission revises the rule to reflect that ERCOT should select least cost actions and treat all customers equally except in emergency situations when these standards will not reasonably allow ERCOT to maintain system reliability.

§25.200(d), System reliability

LCRA questioned the absolute requirement that the TSP consult with ERCOT before interrupting transmission service in the event of an adverse condition or disturbance on the TSP system, as required under §25.200(d)(1). LCRA argued that this is impractical in cases of emergency or life-threatening situations. In addition, LCRA considered the pre-consultation requirement confusing given that §25.200(d)(2) requires that the TSP give as much "advance notice as practicable" before interrupting service. LCRA recommended that the language be revised to require consultation "only if practical". Reliant responded that it agreed with LCRA and proposed that the wording "in consultation with ERCOT and" be deleted from §25.200(d).

The commission agrees with LCRA that there may be circumstances in which it may not be practical for a TSP to consult with ERCOT prior to interrupting service. However, this should only occur in exceptional situations. The commission therefore rejects Reliant's proposal to delete all consultation requirements from §25.200(d). The commission revises the rule to reflect that consultation with ERCOT should occur unless this is impractical due to an emergency situation.

ERCOT stated that beginning June 1, 2001, ERCOT would be responsible for all scheduling, dispatch, transmission congestion management, and emergency operation in the ERCOT region. ERCOT argued that the commission has long recognized that such responsibility, particularly in maintaining electric service stability and safety, requires some reasonable limitation of liability. ERCOT claimed that there should therefore be some limitation of liability for ERCOT operations, similar to the traditional control area utility liability limitation, and offered language to that effect.

Mirant responded that it agreed with ERCOT's position that ERCOT is entitled to some liability limitations, but stated that the language proposed by ERCOT leaves ERCOT with no accountability. Mirant proposed language that would have transmission service interruptions be "consistent with good utility practice and on a non-discriminatory basis." FPLE also opposed the proposed changes by ERCOT on the basis that they are inconsistent with the Protocols and result in reopening of one aspect of the Standard Form Agreement. In doing so, the ERCOT proposal would confuse how the liability limitation will interact not only with the Protocols and Standard Form Agreements, but also with the other provisions of the proposed rule. FPLE argued that the proposed change is vague and unclear in its effect and impact, and should be rejected.

The commission believes that ERCOT should have the authority to interrupt transmission service to maintain system reliability, to make necessary adjustments and repairs to its facilities, or to prevent danger to persons or property. However, the commission also believes that this authority should not be unlimited and that ERCOT's behavior should at all times be guided by good utility practice and a degree of reasonableness. Therefore, the commission adopts language that exonerates ERCOT from liability caused by its ordinary negligence but leaves ERCOT subject to liability for its gross negligence or intentional misconduct.

TEC commented that it was not clear under §25.200(d)(3) as to what obligation or contract the TSC would be in default, and as to whether this applied to the DSP or the qualifying scheduling entity (QSE). AEP replied that the DSP can not be in default because the DSP is not the TSP customer. According to AEP the DSP merely acts as the billing agent for the TSP and has no responsibility for scheduling. At the public hearing, TXU stated that there are situations in which the DSP is the customer of the TSP. AEP responded with a clarification that the DSP is not a customer of the TSP for the purpose of scheduling, and that this is the role of the QSE.

The commission agrees with the clarifications by TXU and AEP, but finds any revision to the rule unnecessary.

§25.202. Commercial Terms for Transmission Service.

§25.202(a), Billing and payment

Cap Rock, Garland/Denton, Greenville, and TMPA (parties) stated that the proposed rules create confusion as to who will be billed for transmission service. These parties interpreted §25.202 to require that transmission service tariffs and bills be applied to all DSPs and any entity scheduling the export of power from ERCOT. These parties commented that the extent to which entities other than the DSPs are included in the definition of eligible transmission service customer under §25.5(24) (relating to Definitions), they are apparently not subject to tariffs and will not be billed. According to these parties, the amended rule could preclude certain entities from paying for transmission service, particularly the MOUs and cooperatives providing bundled service to other MOUs and cooperatives. These parties proposed language modification to §25.202(a) that would clarify that invoices would be issued to an eligible TSC taking service under the TSP's applicable tariffs.

AEP responded to the above parties that deleting DSPs as the recipients of the invoices for transmission service from TSPs from subsection (a) is contrary to Order Number 40 in Docket Number 22344, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Substantive Rule 25.344*, and should therefore be rejected.

The commission agrees with AEP that, consistent with Order Number 40 in Docket Number 22344, the DSP is the recipient of invoices for transmission services. The commission therefore declines to make the requested revision.

In reference to subsection (a)(1), addressing the payment of an invoice by a DSP to a TSP, STEC objected to the change that allows the TSC 35 days rather than 20 calendar days to pay an invoice for transmission service because it would place a burden on smaller cooperatives and MOUs that will experience cash flow problems. TXU disagreed with STEC, arguing that this change provides a consistency with the timeframe of 35 days in which the REP must pay the DSP, thus giving the DSP the opportunity to receive payment from the REP before paying the TSP. In addition, TXU argued that this change will create symmetry for the majority of transactions in ERCOT.

The commission finds that the timeframe under which the TSC pays for transmission service should be consistent with the timeframe allowed for the REP to pay the DSP.

Regarding §25.202(a)(1), Reliant commented that the proposed language allowing the TSP and the TSC to establish another mutually agreeable deadline is in conflict with commission Order Number 40 in Docket Number 22344. According to Reliant, the commission found in that order that the ERCOT TSPs should bill distribution utilities, which would then bill REPs a combined transmission and distribution (T&D) charge. Reliant argued that the language in the rule should be consistent with Order Number 40 and, accordingly, recommended replacing the TSC with the DSP.

Under Order Number 40 in Docket Number 22344, the commission did find that the ERCOT TSPs should bill distribution utilities, which would then bill REPs a combined T&D charge. In addition, the commission found that the TSPs would bill other entities that export power outside the ERCOT region, such as power marketers, directly. The TSP customers would include both DSPs and other entities. The commission therefore declines to make the revision.

The AEP companies stated that the term "prime commercial paper rate" used in §25.202(a)(2) is potentially ambiguous because while banks have prime lending rates, commercial paper is rated under a different system. AEP proposed replacing "prime commercial paper rate" with a 30-day London Interbank Offered Rate (LIBOR) as reported in the Money Rates section of the Wall Street Journal, plus 100 points. According to AEP, the proposed revision would achieve more certainty and specify a short-term rate that is used as a benchmark by many corporations and is subject to verification. TXU also commented that the proposed language in §25.202(a)(2) requires an unnecessarily complicated process for calculating interest that will lead to confusion and disputes. TXU recommended that the policy be revised to have the interest rates applicable to overbillings and underbillings set annually by the commission, as required under Texas Utilities Code Annotated Chapter 183. STEC supported the TXU proposal.

The commission agrees with TXU and AEP that the use of the term "prime commercial paper rate" used in §25.202(a)(2) is potentially ambiguous because while banks have prime lending rates, commercial paper is rated under a different system. The commission further finds that the use of a 30-day LIBOR as reported in the Money Rates section of the Wall Street Journal, plus 100 points may also lead to confusion and less certainty. The commission therefore finds that interest rates applicable to overbillings and underbillings set annually by the commission, as required under Texas Utilities Code Annotated, Chapter 183, is the most appropriate mechanism for determining the interest rate. The commission revises §25.202(a)(2) accordingly.

Reliant proposed additional language to §25.202(a)(2) that clarifies and provides for the consolidation of payments between parties. STEC in comments submitted at the public hearing opposed Reliant's proposal to amend §25.202(a)(2), stating it was unnecessary. STEC stated that the commission should continue to use a netting matrix at it has done in the past for payment and billing purposes.

Currently, the consolidation of payments occurs through a netting matrix. This netting matrix is not prescribed by commission substantive rules, but occurs by commission order. As proposed, the rule will not prevent the commission from requiring netting in the future. The commission therefore finds that it is unnecessary to prescribe the netting matrix in the proposed rules and declines to make the revision.

In reference to §25.202(a)(3), TXU commented that the provision that allows a TSP to initiate a proceeding with the commission to terminate a TSC who is in default is not workable. According to TXU, this would give little remedy in the case where a TSC is not directly connected to the TSP, and it would therefore be practically impossible to "terminate" such a customer. Accordingly, TXU proposes a revision to §25.202(a)(3)(A) that would have the customer pay triple the amount that the customer has failed to pay, in addition to any other remedy ordered by the commission. TEC raised the concern that a cooperative DSP may be in default because a non-affiliated competitive retailer is delinquent in paying the cooperative. In addition, TEC stated that the proposed language provides little direction relative to the process by which service is terminated and how electric service will be maintained for the retail electric customers served by the affiliates of a DSP in default.

Mirant and TEC in reply comments disagreed with TXU's proposal that would require a customer that defaults to pay three times what it failed to pay plus any remedy ordered by the commission. TEC also opposed the level of TXU's proposed penalty, but it agreed that a proceeding to terminate service offered little remedy in cases where the customer in default is not connected directly to the TSP. Mirant proposed that the remedy be limited to termination of service.

STEC replied that provision must be made for the TSP to terminate service to customers in default, because smaller TSPs could experience cash flow problems if transmission customers refuse to pay their bills promptly. STEC also supported the TXU proposal that there be a penalty for a customer who has failed to pay for transmission service, with the modification that the penalty be reduced from three times the amount the customer has failed to pay to two times the amount the customer has failed to pay.

The commission agrees that termination will provide little remedy in the case where a customer is not directly connected to the TSP. Therefore, it is appropriate to have some payment penalty to guarantee payment. The penalty should be more than paying interest because, if a customer finds that paying interest is of economic benefit in the long run, it would leave the TSP without a remedy. However, having the customer pay an amount three times the default amount is excessive. The commission agrees with STEC that setting a penalty at twice the amount that is in default, in addition to any other remedy ordered by the commission, is appropriate. The commission has revised the rule accordingly.

§25.202(b), Indemnification and liability, and (c), Creditworthiness for transmission service.

TXU commented that, throughout §25.202(b) and (c) of the proposed rule, reference is made only to the TSP. However, the subsections should also apply to a DSP that provides transmission service over distribution voltage facilities. Therefore, TXU recommended that the reference to the "TSP" should be replaced with a reference to both the "TSP and DSP."

The commission concludes that an entity that is providing such service is a TSP, under the definition in §25.5 and under §25.191(d) and declines to make the change.

TEC raised two concerns regarding §25.202(c)(1). First, TEC commented that this subsection sets no guidelines by which the TSP may establish creditworthiness standards for its customers. According to TEC, this discretion in establishing varying standards would allow the TSP to favor its affiliates. To correct this problem, TEC proposed tying the amount of the security necessary to protect against losses to the amount of the transmission customer's load, and to eliminate the need for a security after the TSC has established a 12-month history of full and timely payments. Second, TEC claimed that this provision could eliminate the ability of cooperatives to obtain transmission service because many cooperatives have existing mortgages secured by liens on all assets. TEC proposed curing this problem by exempting cooperatives from all security maintenance requirements if (1) their total generation, transmission and distribution plant in service is in excess of $10,000,000, or (2) they have taken transmission service prior to the adoption of this rule and have not defaulted on transmission payment obligations.

TXU responded to TEC that the creditworthiness standards under proposed §25.202(c)(1) are virtually the same as under the current rule, and that TEC failed to explain why there is any reason to believe that its fears will be realized in the future, when they have not occurred in the past. TXU claimed to be unaware of any instance in which an electric cooperative has been required to demonstrate creditworthiness in order to obtain transmission service. Reliant responded that TEC is requesting a special classification of creditworthiness that is unnecessary. According to Reliant, this issue is addressed in the ERCOT protocols and in Substantive Rule §25.214.

TEC responded that the creditworthiness requirements established in the ERCOT protocols are meant to address security for participation in the ERCOT market and those established in Substantive Rule §25.214 allow creditworthiness to be established on a company specific basis for the purpose of retail access by IOUs. Thus, according to TEC, the protocols and Substantive Rule §25.214 do not address the creditworthiness necessary to receive transmission service. TEC further objected to TXU's assertion that TEC was attempting to carve out exceptions for cooperatives and MOUs, arguing that these exceptions would apply equally to smaller IOUs such as Sharyland. STEC disagreed with TEC, maintaining that TSPs have been required to provide and maintain a letter of credit in the past, and that this requirement has not been a problem for cooperatives. STEC stated that without some security of timely payment by the transmission customer, the TSPs will face financial problems, including having their credit ratings downgraded.

The creditworthiness standards proposed in the rule are the same as the standards under the existing rule. These standards have not presented a problem to cooperatives in the past, and the standards should not prevent a cooperative from acquiring transmission service in the future. The commission finds that the language in the proposed rule does reflect that these standards should be reasonable and in accordance with standard commercial practices. The commission also finds that the proposed standards should be and are consistent with the credit standards in the rules related to terms and conditions for delivery of service. The commission does, however, agree with TEC that a TSP should not have the discretion to establish varying standards that would allow the TSP to favor its affiliate. The commission revises the rule to reflect that any standards developed by the TSP must be applied in a non-discriminatory fashion.

§25.203. Alternative Dispute Resolution (ADR).

§25.203(c), Mediation or arbitration

The existing rule provides that arbitration is available to any party if informal negotiations have been unsuccessful and that mediation is only available upon agreement of all parties. FPLE supported continuation of this approach, and noted that the proposed rules shift these dynamics without explanation. FPLE further argued that in Docket Number 23220, *Petition of the Electric Reliability Council of Texas (ERCOT) for Approval of the ERCOT Protocols*, the commission voiced its opinion that it prefers non-binding arbitration to be the default ADR procedure. FPLE also argued that the ADR provisions are procedural in nature, and do not affect any substantive aspect of the new market design prescribed by the Protocols for ERCOT. FPLE believed that the commission should be concerned not only that the transmission rule reflects the new ERCOT market design, but also that the market power of TSPs is mitigated to the maximum extent possible. Mirant agreed with FPLE on this issue. Garland/Denton and Greenville opposed FPLE's recommendation. It was their view that parties should not be forced into a time consuming and expensive arbitration proceeding when mediation could resolve a dispute in a more cost effective manner. At the hearing, Constellation added that arbitrators are usually experts in this field, while mediators may not be. Constellation also added that there is no clear time line in the rule, which delays projects from going to the commission. STEC responded at the hearing that mediation is less expensive than arbitration, and SOAH has experienced mediators. Finally, FPLE added that if mediation is the default method, a time line to bring issues to the commission should be established.

The commission agrees that mediation should not be used to delay the resolution of a dispute and that only if all parties continue to put forth a good-faith effort is mediation a meaningful ADR option. The commission amends the proposed rule to better track the options available to parties in existing rules, and is confident that the opportunity for strategic gaming of the process does not remain. The adopted language adjustments allow that, if at any point prior to or during mediation good faith is breached, any party to the dispute may request arbitration.

Proposed deletion of existing §25.203(i)(2), Effect on rights under law (now (f)(2))

TXU, Garland/Denton, and Greenville all agreed that given the public utility obligations of TSPs that will remain in effect following restructuring, it would be advisable for the commission to retain the text of existing subsection (i)(2) of existing rules in the event a TSP believes it necessary to seek relief directly from the commission without going through the transmission rule ADR process.

The commission agrees with TXU, Garland/Denton, and Greenville and inserts as §25.203(f)(2) a modified version of existing §25.203(i)(2) for use in the event a TSP deems it necessary to seek relief directly from the commission without completing the transmission rule ADR process. The commission encourages parties to seek alternative dispute resolution, but agrees that when parties have entrenched differences, it is a waste of resources to spend time going through ADR procedures.

SUBCHAPTER O. UNBUNDLING AND MARKET POWER.

DIVISION 2. Independent Organizations.

§25.361. Electric Reliability Council of Texas (ERCOT).

§25.361(a), Applicability.

TXU commented that the last two sentences of §25.361(a) should be deleted, claiming they could lead to unnecessary confusion, and that the second sentence be revised to refer to both TSPs and DSPs.

The commission agrees that it is preferable to rely on the definitions in §25.5, rather than redefining TSP and transmission service customer in this section. There are also instances in which ERCOT has authority with respect to DSPs, so they should be referred to in this subsection.

§25.361(b), Purpose

Garland/Denton offered modifications to this subsection to make it clear that the independent system operator is only responsible for ensuring "access to" the transmission system and distribution systems, and not "over" the distribution systems of MOUs that have not implemented customer choice.

The commission believes the proposed language is adequate and adopts it with a reference to §25.191(d), which describes the obligation to provide transmission service in ERCOT by each TSP and DSP in ERCOT.

§25.361(c), Functions

ERCOT suggested revising the list of ERCOT functions in §25.361(c)(1) by deleting "ERCOT transmission tariffs, including determining whether a person is eligible for transmission service" and adding "operational and market functions of the ERCOT system, including scheduling of resources and loads, and transmission congestion management, as set forth in the ERCOT protocols." TMPA suggested that §25.361(c)(1) should provide that ERCOT determine eligibility of transmission service customers. TXU suggested that §25.361(c)(1) be changed to "ensure access to the transmission and distribution systems for all buyers and sellers of electricity on non-discriminatory terms" and to include as a separate ERCOT function, "administer, on a daily basis, the ERCOT transmission tariffs, including determining whether a person is eligible for transmission service."

The commission adopts ERCOT's suggested language and otherwise concludes that the proposed changes are unnecessary.

ERCOT suggested deleting §25.361(c)(2) "serve as the single point of contact for the initiation of transmission transactions." TXU suggested retaining the above language as (7) and added the following as, "(2) ensure the reliability and adequacy of the regional electrical network."

The commission concludes that serving as the "single point of contact" for transmission service is an important function that ERCOT should continue to perform. The commission also agrees with TXU that ERCOT's ensuring the reliability and adequacy of the regional network is a key function that should be listed.

ERCOT and TXU suggested deleting §25.361(c)(4), "receive and approve scheduling of ERCOT generation and transmission transactions."

The commission agrees with the deletion of subsection (c)(4), as this function is now included in the amended §25.361(c)(1), as adopted.

TXU suggested deleting §25.361(c)(5) in its entirety.

The commission sees "the curtailment and redispatch of ERCOT generation and transmission transactions on a non-discriminatory basis, consistent with ERCOT protocols" as critical ERCOT functions and therefore does not adopt TXU's suggestion.

ERCOT, Reliant, and TXU suggested that §25.361(c)(10) be deleted entirely.

The commission agrees that §25.361(c)(10) will be inconsistent with the ERCOT protocols and that the Alternative Dispute Resolution (ADR) procedure in the ERCOT protocols will serve the market participants in the event ADR is necessary. The commission therefore deletes §25.361(c)(10), as proposed.

TXU suggested that proposed §25.361(c)(13) be deleted entirely.

The commission disagrees with TXU and believes that the monitoring of generation planned outages is critical to maintaining adequate generating capacity in the ERCOT region.

New §25.361(e), Liability

ERCOT proposed a new subsection (e) to shelter it from liability in certain situations. ERCOT's proposed language is essentially a *force majeure* clause with an additional limitation of liability appended to the end relating to the making of necessary repairs upon property or equipment.

The commission believes that ERCOT should be protected with a *force majeure* clause and adopts the *force majeure* clause that was approved for the investor owned utilities in Substantive Rule §25.214. However, the commission does not believe it is appropriate to include in the rule a limitation of liability for the making of necessary repairs upon property or equipment. A limitation of liability is being adopted in §25.200(d), which gives ERCOT the authority to interrupt transmission service to make necessary repairs to facilities, making it subject to liability only for its gross negligence and intentional misconduct. The commission believes that this limitation, which is consistent with the rule applicable to utilities in the provision of delivery service, is appropriate.

Proposed §25.361(e), Planning (now (f))

Reliant commented that proposed §25.361(e) should retain the language found in existing rule §25.197(f) that clarifies ERCOT's limited role with respect to planning of local facilities. Reliant suggested additional language to clarify that review and approval by ERCOT is not a requirement for transmission projects to move forward, and repeal of the sentence, "ERCOT shall supervise and coordinate the other planning activities of TSPs." Reliant suggested adding the following language in the introductory portion of the subsection: "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. ERCOT review and approval is neither required nor recommended for local transmission projects." TXU also commented on the new language proposed in the introductory portion of the subsection, namely, "ERCOT shall supervise and coordinate the other planning activities of TSPs." TXU recommended that to avoid confusion and uncertainty as to what the commission intended with this slight wording change, the existing language be retained, with only relevant terminology modifications.

The commission adopts proposed §25.361(e) as published, except renumbered as (f). The commission believes that coordination of the planning of the ERCOT transmission system is key to identifying the needs of the system and especially those needs that have resulted from constraints to the transfer of bulk electric power for either reliability or commercial reasons. Currently, ERCOT has set up five regional transmission planning groups, which include staff from the commission's Electric Division, ERCOT, and the TSPs, who evaluate projects that require certificate of convenience and necessity (CCN) applications. Regional planning should result in more efficient and effective identification of problems in the ERCOT transmission system and plans for addressing the problems. The commission believes that bulk transmission planning is best served if ERCOT supervises and coordinates the planning activities of the TSPs.

Proposed §25.361(f), Information and coordination (now (g))

TXU suggested that proposed §25.361(f) be deleted, because the requirements of the subsection are addressed in the ERCOT protocols.

The commission concludes that a broad standard for handling information is appropriate as proposed.

Proposed §25.361(h), ERCOT administrative fee (now (i))

Regarding proposed §25.361(h), ERCOT and TXU suggested the addition of a reference to the ERCOT protocols.

The commission agrees with the parties and revises proposed §25.361(h), renumbered as (i) to reference the ERCOT protocols.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting these sections, the commission makes other minor modifications for the purpose of clarifying its intent.

These amendments, new rules and repeals are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2001) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction. In addition, in adopting revisions to the commission's transmission rules consistent with the new ERCOT market design, the commission relies on the following PURA provisions: §35.002, which specifies the providers of generation that may compete for the business of selling power at wholesale; §35.004, which relates to the provision of wholesale transmission service; §35.005, which relates to the commission's authority to order transmission service; §35.006, which requires the commission to adopt rules relating to wholesale transmission service, rates, and access; §35.007, which relates to the filing of a compliance tariff by a utility that owns or operates a transmission facility; §35.008, which grants the commission authority to order nonbinding alternative dispute resolution for parties to a dispute concerning wholesale transmission service; §39.001(a)-(b), which set out a legislative finding that a competitive retail electric market is in the public interest; §39.151, which requires the commission to certify independent organizations to ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms, ensure the reliability and adequacy of the regional electrical network, ensure that information relating to a customer's choice of REP is conveyed in a timely manner to the persons who need that information, and ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region; and §39.203(a), which relates to a transmission and distribution utility's required provision of transmission and distribution service.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 35.002, 35.004-35.008, 39.001(a)-(b), 39.151, and 39.203(a).

SUBCHAPTER A. GENERAL PROVISIONS.

§25.5. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Above-market purchased power costs** — Wholesale demand and energy costs that a utility is obligated to pay under an existing purchased power contract to the extent the costs are greater than the purchased power market value.

(2) **Administrative review** — A process under which an application may be approved without a formal hearing.

(3) **Affected person** — means:

(A) a public utility or electric cooperative affected by an action of a regulatory authority;

(B) a person whose utility service or rates are affected by a proceeding before a regulatory authority; or

(C) a person who:

(i) is a competitor of a public utility with respect to a service performed by the utility; or

(ii) wants to enter into competition with a public utility.

(4) **Affiliate** — means:

(A) a person who directly or indirectly owns or holds at least 5.0% of the voting securities of a public utility;

(B) a person in a chain of successive ownership of at least 5.0% of the voting securities of a public utility;

(C) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by a public utility;

(D) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by:

(i) a person who directly or indirectly owns or controls at least 5.0% of the voting securities of a public utility; or

(ii) a person in a chain of successive ownership of at least 5.0% of the voting securities of a public utility;

(E) a person who is an officer or director of a public utility or of a corporation in a chain of successive ownership of at least 5.0% of the voting securities of a public utility; or

(F) a person determined to be an affiliate under Public Utility Regulatory Act §11.006.

(5) **Affiliated power generation company —** A power generation company that is affiliated with or the successor in interest of an electric utility certificated to serve an area.

(6) **Affiliated retail electric provider —** A retail electric provider that is affiliated with or the successor in interest of an electric utility certificated to serve an area.

(7) **Aggregator —** A person joining two or more customers, other than municipalities and political subdivision corporations, into a single purchasing unit to negotiate

the purchase of electricity from retail electric providers. Aggregators may not sell or take title to electricity. Retail electric providers are not aggregators.

(8) **Aggregation —** Includes the following:

(A) the purchase of electricity from a retail electric provider, a municipally owned utility, or an electric cooperative by an electricity customer for its own use in multiple locations, provided that an electricity customer may not avoid any nonbypassable charges or fees as a result of aggregating its load; or

(B) the purchase of electricity by an electricity customer as part of a voluntary association of electricity customers, provided that an electricity customer may not avoid any nonbypassable charges or fees as a result of aggregating its load.

(9) **Ancillary service —** A service necessary to facilitate the transmission of electric energy including load following, standby power, backup power, reactive power, and any other services the commission may determine by rule.

(10) **Base rate** — Generally, a rate designed to recover the costs of electricity other than costs recovered through a fuel factor, power cost recovery factor, or surcharge.

(11) **Commission —** The Public Utility Commission of Texas.

(12) **Control area** — An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(A) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(B) maintain, within the limits of good utility practice, scheduled interchange with other control areas;

(C) maintain the frequency of the electric power system(s) within reasonable limits in accordance with good utility practice; and

(D) obtain sufficient generating capacity to maintain operating reserves in accordance with good utility practice.

(13) **Corporation** — A domestic or foreign corporation, joint-stock company, or association, and each lessee, assignee, trustee, receiver, or other successor in interest of the corporation, company, or association, that has any of the powers or privileges of a corporation not possessed by an individual or partnership. The term does not include a municipal corporation or electric cooperative, except as expressly provided by the Public Utility Regulatory Act.

(14) **Customer choice** — The freedom of a retail customer to purchase electric services, either individually or through voluntary aggregation 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.

(15) **Customer class** — A group of customers with similar electric usage service characteristics (e.g., residential, commercial, industrial, sales for resale) taking

service under one or more rate schedules. Qualified businesses as defined by the Texas Enterprise Zone Act, Texas Government Code, Title 10, Chapter 2303 may be considered to be a separate customer class of electric utilities.

(16) **Demand-side management** — Activities that affect the magnitude and/or timing of customer electricity usage.

(17) **Demand-side resource or demand-side management resource** — Activities that result in reductions in electric generation, transmission, or distribution capacity needs or reductions in energy usage or both.

(18) **Distribution line —** A power line operated below 60,000 volts, when measured phase-to-phase.

(19) **Distributed resource** — A generation, energy storage, or targeted demand-side resource, generally between one kilowatt and ten megawatts, located at a customer's site or near a load center, which may be connected at the distribution voltage level (60,000 volts and below), that provides advantages to the system, such as deferring the need for upgrading local distribution facilities.

(20) **Distribution service provider (DSP)** — an electric utility, municipally-owned utility, or electric cooperative that owns or operates for compensation in this state equipment or facilities that are used for the distribution of electricity to retail customers, as defined in this section, including retail customers served at transmission voltage levels.

(21) **Electric cooperative —**

(A) a corporation organized under the Texas Utilities Code, Chapter 161 or a predecessor statute to Chapter 161 and operating under that chapter;

(B) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the State of Texas; or

(C) a successor to an electric cooperative created before June 1, 1999, in accordance with 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.

(22) **Electric Reliability Council of Texas (ERCOT) —** Refers to the organization and, in a geographic sense, refers to the area served by electric utilities, municipally owned utilities, and electric cooperatives that are not synchronously interconnected with electric utilities outside of the State of Texas.

(23) **Electric utility —** Except as provided in Subchapter I, Division 1 of this Chapter, an electric utility is: A person or river authority that owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state. The term includes a lessee, trustee, or receiver of an electric utility and a recreational vehicle park owner who does not comply with Texas Utilities Code, Subchapter C, Chapter 184, with regard to the metered sale of electricity at the recreational vehicle park. The term does not include:

(A) a municipal corporation;

(B) a qualifying facility;

(C) a power generation company;

(D) an exempt wholesale generator;

(E) a power marketer;

(F) a corporation described by Public Utility Regulatory Act §32.053 to the extent the corporation sells electricity exclusively at wholesale and not to the ultimate consumer;

(G) an electric cooperative;

(H) a retail electric provider;

(I) the state of Texas or an agency of the state; or

(J) a person not otherwise an electric utility who:

(i) furnishes an electric service or commodity only to itself, its employees, or its tenants as an incident of employment or tenancy, if that service or commodity is not resold to or used by others;

(ii) owns or operates in this state equipment or facilities to produce, generate, transmit, distribute, sell or furnish electric energy to an electric utility, if the equipment or facilities are used primarily to produce and generate electric energy for consumption by that person; or

(iii) owns or operates in this state a recreational vehicle park that provides metered electric service in accordance with Texas Utilities Code, Subchapter C, Chapter 184.

(24) **ERCOT protocols** — Body of procedures developed by ERCOT to maintain the reliability of the regional electric network and account for the production and delivery of electricity among resources and market participants. The procedures,

initially approved by the commission, include a revisions process that may be appealed to the commission, and are subject to the oversight and review of the commission.

(25) **ERCOT region —** The geographic area under the jurisdiction of the commission that is served by transmission service providers that are not synchronously interconnected with transmission service providers outside of the state of Texas.

(26) **Exempt wholesale generator —** A person who is engaged directly or indirectly through one or more affiliates exclusively in the business of owning or operating all or part of a facility for generating electric energy and selling electric energy at wholesale who does not own a facility for the transmission of electricity, other than an essential interconnecting transmission facility necessary to effect a sale of electric energy at wholesale, and who is in compliance with the registration requirements of §25.105 of this title (relating to Registration and Reporting by Power Marketers, Exempt Wholesale Generators and Qualifying Facilities).

(27) **Existing purchased power contract —** A purchased power contract in effect on January 1, 1999, including any amendments and revisions to that contract resulting from litigation initiated before January 1, 1999.

(28) **Facilities —** All the plant and equipment of an electric utility, including all tangible and intangible property, without limitation, owned, operated, leased, licensed, used, controlled, or supplied for, by, or in connection with the business of an electric utility.

(29) **Freeze period —** The period beginning on January 1, 1999, and ending on December 31, 2001.

(30) **Generation assets —** All assets associated with the production of electricity, including generation plants, electrical interconnections of the generation plant to the transmission system, fuel contracts, fuel transportation contracts, water contracts, lands, surface or subsurface water rights, emissions-related allowances, and gas pipeline interconnections.

(31) **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.

(32) **Hearing** — Any proceeding at which evidence is taken on the merits of the matters at issue, not including prehearing conferences.

(33) **Independent organization** — An independent system operator or other person that is sufficiently independent of any producer or seller of electricity that its decisions will not be unduly influenced by any producer or seller. An entity will be deemed to be independent if it is governed by a board that has three representatives from each segment of the electric market, with the consumer segment being represented by one residential customer, one commercial customer, and one industrial retail customer.

(34) **Independent system operator —** An entity supervising the collective transmission facilities of a power region that is charged with non-discriminatory coordination of market transactions, systemwide transmission planning, and network reliability.

(35) **License** — The whole or part of any commission permit, certificate, approval, registration, or similar form of permission required by law.

(36) **Licensing** — The commission process respecting the granting, denial, renewal, revocation, suspension, annulment, withdrawal, or amendment of a license.

(37) **Market power mitigation plan —** A written proposal by an electric utility or a power generation company for reducing its ownership and control of installed generation capacity as required by the Public Utility Regulatory Act §39.154.

(38) **Market value —** For nonnuclear assets and certain nuclear assets, the value the assets would have if bought and sold in a bona fide third-party transaction or transactions on the open market under the Public Utility Regulatory Act (PURA) §39.262(h) or, for certain nuclear assets, as described by PURA §39.262(i), the value determined under the method provided by that subsection.

(39) **Municipality** — A city, incorporated village, or town, existing, created, or organized under the general, home rule, or special laws of the state.

(40) **Municipally-owned utility** — Any utility owned, operated, and controlled by a municipality or by a nonprofit corporation whose directors are appointed by one or more municipalities.

(41) **Native load customer —** A wholesale or retail customer on whose behalf an electric utility, electric cooperative, or municipally-owned utility, by statute,

franchise, regulatory requirement, or contract, has an obligation to construct and operate its system to meet in a reliable manner the electric needs of the customer.

(42) **Person —** Includes an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative.

(43) **Pleading** — A written document submitted by a party, or a person seeking to participate in a proceeding, setting forth allegations of fact, claims, requests for relief, legal argument, and/or other matters relating to a proceeding.

(44) **Power cost recovery factor —** A charge or credit that reflects an increase or decrease in purchased power costs not in base rates.

(45) **Power generation company —** A person that:

(A) generates electricity that is intended to be sold at wholesale;

(B) does not own a transmission or distribution facility in this state, other than an essential interconnecting facility, a facility not dedicated to public use, or a facility otherwise excluded from the definition of "electric utility" under this section; and

(C) does not have a certificated service area, although its affiliated electric utility or transmission and distribution utility may have a certificated service area.

(46) **Power marketer —** A person who becomes an owner of electric energy in this state for the purpose of selling the electric energy at wholesale; does not own generation, transmission, or distribution facilities in this state; does not have a certificated service area; and who is in compliance with the registration

requirements of §25.105 of this title (relating to Registration and Reporting by Power Marketers).

(47) **Power region —** A contiguous geographical area which is a distinct region of the North American Electric Reliability Council.

(48) **Premises** — A tract of land or real estate including buildings and other appurtenances thereon.

(49) **Proceeding** — A hearing, investigation, inquiry, or other procedure for finding facts or making a decision. The term includes a denial of relief or dismissal of a complaint. It may be rulemaking or nonrulemaking; rate setting or non-rate setting.

(50) **Public utility or utility —** means an electric utility as that term is defined in this section, or a public utility or utility as those terms are defined in the Public Utility Regulatory Act §51.002.

(51) **Public Utility Regulatory Act (PURA)** —The enabling statute for the Public Utility Commission of Texas, located in the Texas Utilities Code Annotated, §§11.001 *et. seq*.

(52) **Purchased power market value —** The value of demand and energy bought and sold in a bona fide third-party transaction or transactions on the open market and determined by using the weighted average costs of the highest three offers from the market for purchase of the demand and energy available under the existing purchased power contracts.

(53) **Qualifying cogenerator** — The meaning as assigned this term by 16 U.S.C. §796(18)(C). A qualifying cogenerator that provides electricity to the purchaser

of the cogenerator's thermal output is not for that reason considered to be a retail electric provider or a power generation company.

(54) **Qualifying facility** — A qualifying cogenerator or qualifying small power producer.

(55) **Qualifying small power producer** — The meaning as assigned this term by 16 U.S.C. §796(17)(D).

(56) **Rate** — A compensation, tariff, charge, fare, toll, rental, or classification that is directly or indirectly demanded, observed, charged, or collected by an electric utility for a service, product, or commodity described in the definition of electric utility in this section and a rule, practice, or contract affecting the compensation, tariff, charge, fare, toll, rental, or classification that must be approved by a regulatory authority.

(57) **Rate class —** A group of customers taking electric service under the same rate schedule.

(58) **Rate year** — The 12-month period beginning with the first date that rates become effective. The first date that rates become effective may include, but is not limited to, the effective date for bonded rates or the effective date for interim or temporary rates.

(59) **Ratemaking proceeding —** A proceeding in which a rate may be changed.

(60) **Regulatory authority** — In accordance with the context where it is found, either the commission or the governing body of a municipality.

(61) **Renewable energy technology** — Any technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly

from the sun, indirectly from the sun or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, on wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, waste products from fossil fuels, or waste products from inorganic sources.

(62) **Renewable resource** — A resource that relies on renewable energy technology.

(63) **Retail customer —** The separately metered end-use customer who purchases and ultimately consumes electricity.

(64) **Retail electric provider —** A person that sells electric energy to retail customers in this state. A retail electric provider may not own or operate generation assets.

(65) **Retail stranded costs —** That part of net stranded cost associated with the provision of retail service.

(66) **River authority —** A conservation and reclamation district created pursuant to the Texas Constitution, Article 16, Section 59, including any nonprofit corporation created by such a district pursuant to the Texas Water Code, Chapter 152, that is an electric utility.

(67) **Rule** — A statement of general applicability that implements, interprets, or prescribes law or policy, or describes the procedure or practice requirements of the commission. The term includes the amendment or repeal of a prior rule, but does not include statements concerning only the internal management or organization of the commission and not affecting private rights or procedures.

(68) **Rulemaking proceeding —** A proceeding conducted pursuant to the Administrative Procedure Act, Texas Government Code, Chapter 2001, Subchapter B, to adopt, amend, or repeal a commission rule.

(69) **Separately metered —** Metered by an individual meter that is used to measure electric energy consumption by a retail customer and for which the customer is directly billed by a utility, retail electric provider, electric cooperative, or municipally owned utility.

(70) **Service —** Has its broadest and most inclusive meaning. The term includes any act performed, anything supplied, and any facilities used or supplied by an electric utility in the performance of its duties under the Public Utility Regulatory Act to its patrons, employees, other public utilities or electric utilities, an electric cooperative, and the public. The term also includes the interchange of facilities between two or more public utilities or electric utilities.

(71) **Spanish-speaking person —** A person who speaks any dialect of the Spanish language exclusively or as their primary language.

(72) **Stranded cost —** The positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, any above-market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of Financial Accounting Standards Number 71 ("Accounting for the Effect of Certain Types of Regulation") for generation-related assets if required by the provisions of the Public Utility Regulatory Act, Chapter 39. For purposes of §39.262, book value shall be established as of December 31, 2001, or the date a

market value is established through a market valuation method under §39.262(h), whichever is earlier, and shall include stranded costs incurred under §39.263.

(73) **Submetering —** Metering of electricity consumption on the customer side of the point at which the electric utility meters electricity consumption for billing purposes.

(74) **Supply-side resource** — A resource, including a storage device, that provides electricity from fuels or renewable resources.

(75) **Tariff** — The schedule of a utility, municipally-owned utility, or electric cooperative containing all rates and charges stated separately by type of service, the rules and regulations of the utility, and any contracts that affect rates, charges, terms or conditions of service.

(76) **Tenant —** A person who is entitled to occupy a dwelling unit to the exclusion of others and who is obligated to pay for the occupancy under a written or oral rental agreement.

(77) **Test year —** The most recent 12 months for which operating data for an electric utility, electric cooperative, or municipally-owned utility are available and shall commence with a calendar quarter or a fiscal year quarter.

(78) **Transmission and distribution utility —** A person or river authority that owns, or operates for compensation in this state equipment or facilities to transmit or distribute electricity, except for facilities necessary to interconnect a generation facility with the transmission or distribution network, a facility not dedicated to public use, or a facility otherwise excluded from the definition of "electric utility" under this section, in a qualifying power region certified under the Public Utility

Regulatory Act (PURA) §39.152, but does not include a municipally owned utility or an electric cooperative.

(79) **Transmission line** — A power line that is operated at 60,000 volts or above, when measured phase-to-phase.

(80) **Transmission service —** Service that allows a transmission service customer to use the transmission and distribution facilities of electric utilities, electric cooperatives and municipally owned utilities to efficiently and economically utilize generation resources to reliably serve its loads and to deliver power to another transmission service customer. Includes construction or enlargement of facilities, transmission over distribution facilities, control area services, scheduling resources, regulation services, reactive power support, voltage control, provision of operating reserves, and any other associated electrical service the commission determines appropriate, except that, on and after the implementation of customer choice in any portion of the ERCOT region, control area services, scheduling resources, regulation services, provision of operating reserves, and reactive power support, voltage control and other services provided by generation resources are not "transmission service".

(81) **Transmission service customer** — A transmission service provider, distribution service provider, river authority, municipally-owned utility, electric cooperative, power generation company, retail electric provider, federal power marketing agency, exempt wholesale generator, qualifying facility, power marketer, or other person whom the commission has determined to be eligible to be a transmission

service customer. A retail customer, as defined in this section, may not be a transmission service customer.

(82) **Transmission service provider (TSP) —** An electric utility, municipally-owned utility, or electric cooperative that owns or operates facilities used for the transmission of electricity.

(83) **Transmission system** — The transmission facilities at or above 60 kilovolts owned, controlled, operated, or supported by a transmission service provider or transmission service customer that are used to provide transmission service.

SUBCHAPTER I. TRANSMISSION AND DISTRIBUTION.

DIVISION 1. Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas.

§25.191. Transmission Service Requirements.

(a) **Purpose.** The purpose of Subchapter I, Division 1 of this chapter (relating to Transmission and Distribution), is to clearly state the terms and conditions that govern transmission access in order to:

(1) facilitate competition in the sale of electric energy in Texas;

(2) preserve the reliability of electric service; and

(3) enhance economic efficiency in the production and consumption of electricity.

(b) **Applicability.** Unless otherwise explicitly provided, Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas) applies to transmission service providers (TSPs), as defined in §25.5 of this title (relating to Definitions), which include river authorities and other electric utilities, municipally-owned utilities, and electric cooperatives. The transmission service standards described in Division 1 of this subchapter also apply to transmission service to, from, and over the direct-current interconnections between the Electric Reliability Council of Texas (ERCOT) region and areas outside of the ERCOT region (DC ties), to the extent that tariffs for such service incorporating the terms of Division 1 of this subchapter are approved for the transmission providers that own an interest in the interconnections. Some provisions of Division 1 explicitly apply to distribution service providers (DSPs), as defined in §25.5 of this title.

(c) **Nature of transmission service.** Transmission service allows for power delivery from generation resources to serve loads, inside and outside of the ERCOT region. Service provided pursuant to Division 1 of this subchapter permits municipally-owned utilities, electric cooperatives, power marketers, power generation companies, qualifying scheduling entities, retail electric providers (REPs), qualifying facilities, and distribution service providers (DSPs) to use the transmission systems of the TSPs in ERCOT. Transmission service shall be provided pursuant to Division 1 of this subchapter, commission-approved tariffs, the ERCOT protocols and, for TSPs subject to Federal Energy Regulatory Commission (FERC) jurisdiction, FERC requirements. Transmission service under Division 1 of this subchapter includes the provision of transmission service to an entity that is scheduling the export or import of power from the ERCOT region across a DC tie. The rules in Division 1 of this subchapter do not require a municipally owned utility or electric cooperative that has not opted for customer choice to provide transmission service to a retail electric provider or retail customer in connection with the retail sale of electricity in its exclusive service area.

(d) **Obligation to provide transmission service.** Each TSP in ERCOT shall provide transmission service in accordance with the provisions of Division 1 of this subchapter.

(1) Where a TSP has contracted for another person to operate its transmission facilities, the person assigned to operate the facilities shall carry out the operating responsibilities of the TSP under Division 1 of this subchapter.

(2) The obligation to provide comparable transmission service applies to a TSP, even if the TSP's interconnection with the transmission service customer is through distribution, rather than transmission facilities. An electric cooperative that has not opted for customer choice or a municipally owned utility that has not opted for customer choice shall provide wholesale transmission service at distribution voltage when necessary to serve a wholesale customer.

(A) A TSP or a DSP that owns facilities for the delivery of electricity to a transmission service customer purchasing electricity at wholesale using facilities rated at less than 60 kilovolts shall provide the customer access to its facilities on a non-discriminatory basis.

(B) A TSP or DSP shall provide access to its facilities at the distribution level to a transmission service customer, in order to transmit power to a retail customer in an area in which the transmission service customer has the right to provide retail electric service. Such service shall be provided on a non-discriminatory basis and in accordance with PURA §39.203(h).

(C) A DSP shall file a tariff with the commission for wholesale transmission service at distribution level voltage if:

(i) The DSP is currently providing wholesale transmission service at distribution voltage; or

(ii) The DSP receives a valid request to provide wholesale transmission service at distribution voltage. The DSP shall file the tariff within 30 days of receiving the request.

(3) A TSP shall interconnect its facilities with new generating sources and construct facilities needed for such an interconnection, in accordance with Division 1 of this subchapter. A TSP shall use all reasonable efforts to communicate promptly with a power generation company to resolve any questions regarding the requests for service in a non-discriminatory manner. If a TSP or a power generation company is required to complete activities or to negotiate agreements as a condition of service, each party shall use due diligence to complete these actions within a reasonable time.

§25.192. Transmission Service Rates.

(a) **Tariffs.** Each transmission service provider (TSP) shall file a tariff for transmission service to establish its rates and other terms and conditions and shall apply its tariffs and rates on a non-discriminatory basis. The tariff shall apply to all distribution service providers (DSPs) and any entity scheduling the export of power from the Electric Reliability Council of Texas (ERCOT) region.

(b) **Charges for transmission service delivered within ERCOT.** DSPs shall incur transmission service charges pursuant to the tariffs of the TSP.

(1) A TSP's transmission rate shall be calculated as its commission-approved transmission cost of service divided by the average of ERCOT coincident peak demand for the months of June, July, August and September (4CP). A TSP's transmission rate shall remain in effect until the commission approves a new rate. The TSP's annual rate shall be converted to a monthly rate. The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP.

(2) Payments for transmission services shall be consistent with commission orders, approved tariffs, and §25.202 of this title (relating to Commercial Terms for Transmission Service).

(c) **Transmission cost of service.** The transmission cost of service for each TSP shall be based on the expenses in Federal Energy Regulatory Commission (FERC) expense accounts 560-573 (or accounts with similar contents or amounts functionalized to the transmission function) plus the depreciation, federal income tax, and other associated taxes, and the commission-allowed rate of return based on FERC plant accounts 350-359 (or accounts with similar contents or amounts functionalized to the transmission function), less accumulated depreciation and accumulated deferred federal income taxes, as applicable.

(1) The following facilities are deemed to be transmission facilities:

(A) power lines, substations, reactive devices, and associated facilities, operated at 60 kilovolts or above, including radial lines operated at or above 60 kilovolts, except the step-up transformers and a protective device associated with the interconnection from a generating station to the transmission network;

(B) substation facilities on the high side of the transformer, in a substation where power is transformed from a voltage higher than 60 kilovolts to a voltage lower than 60 kilovolts;

(C) the portion of the direct-current interconnections with areas outside of the ERCOT region (DC ties) that are owned by a TSP in the ERCOT region, including those portions of the DC tie that operate at a voltage lower than 60 kilovolts; and

(D) capacitors and other reactive devices that are operated at a voltage below 60 kilovolts, if they are located in a distribution substation, the load at the substation has a power factor in excess of 0.95 as measured or calculated at the distribution voltage level without the reactive devices, and the reactive devices are controlled by an operator or automatically switched in response to transmission voltage.

(E) As used in subparagraphs (A) - (D) of this paragraph, reactive devices do not include generating facilities.

(2) For municipal utilities, river authorities, and electric cooperatives, the commission may permit the use of the cash flow method or other reasonable alternative methods of determining the annual transmission revenue requirement, including the return element of the revenue requirement, consistent with the rate actions of the rate-setting authority for a municipal utility.

(3) For municipal utilities, river authorities, and electric cooperatives, the return may be determined based on the TSP's actual debt service and a reasonable coverage ratio. In determining a reasonable coverage ratio, the commission will consider the coverage ratios required in the TSP's bond indentures or ordinances and the most recent rate action of the rate-setting authority for the TSP.

(4) The commission may adopt rate-filing requirements that provide additional details concerning the costs that may be included in the transmission costs and how such costs should be reported in a proceeding to establish transmission rates.

(d) **Billing units.** No later than December 1 of each year, ERCOT shall determine and file with the commission the current year's average 4CP demand for each DSP, or the DSP's agent for transmission service billing purposes, as appropriate, which shall be used to bill transmission service for the next year. The ERCOT average 4CP demand shall be the sum of the coincident peak of all of the ERCOT DSPs for the four intervals coincident with ERCOT system peak for the months of June, July, August, and September, divided by four. As used in this section, a DSP's average 4CP demand is determined from the total demand, coincident with the ERCOT 4CP, of all customers connected to a DSP, including load served at transmission voltage. The measurement of the coincident peak shall be in accordance with commission-approved ERCOT protocols.

(e) **Transmission rates for exports from ERCOT.** Transmission service charges for exports of power from ERCOT will be assessed to transmission service customers for transmission service within the boundaries of the ERCOT region, in accordance with this section and the ERCOT protocols.

(1) A transmission service customer shall be assessed a transmission service charge for the use of the ERCOT transmission system in exporting power from ERCOT based on the megawatts that are actually exported, the duration of the transaction and the rates established under subsections (c) and (d) of this section. Billing intervals shall consist of a year, month, week, day, or hour.

(2) The monthly on-peak transmission rate will be one-fourth the TSP's annual rate, and the monthly off-peak transmission rate will be one-twelfth its annual rate. The peak period used to determine the applicable transmission rate for such transactions shall be the months of June, July, August, and September.

(3) The DSP or an entity scheduling the export of power over a DC tie is solely responsible to the TSP for payment of transmission service charges under this subsection.

(4) A transmission service customer's charges for use of the ERCOT transmission system for export purposes on a monthly basis shall not exceed the annual transmission charge for the transaction.

(f) **Transmission revenue.** Revenue from the transmission of electric energy out of the ERCOT region over the DC ties that is recovered under subsection (e) of this section shall be credited to all transmission service customers as a reduction in the transmission cost of service for TSPs that receive the revenue.

(g) **Revision of transmission rates.** Each TSP in the ERCOT region shall periodically revise its transmission service rates to reflect changes in the cost of providing such services. Any request for a change in transmission rates shall comply with the filing requirements established by the commission under this section.

(1) Each TSP in the ERCOT region may on an annual basis update its transmission rates to reflect changes in its invested capital. If the TSP elects to update its transmission rates, the new rates shall reflect the addition and retirement of transmission facilities and include appropriate depreciation, federal income tax and other associated taxes, and the commission-allowed rate of return on such facilities as well as changes in loads.

(2) An update of transmission rates under paragraph (1) of this subsection shall be subject to reconciliation at the next complete review of the TSP's transmission cost of service. The commission shall review whether the cost of transmission plant additions are reasonable and necessary at the next complete review of the TSP's transmission cost of service. Any over-recovery of costs, as a result of the update, is subject to refund.

(3) The commission may prescribe a schedule for providers of transmission services to file proceedings to revise the rates for such services.

(4) A DSP may expeditiously pass through to its customers changes in wholesale transmission rates approved by the commission, pursuant to §25.193 of this title (relating to Distribution Service Provider Transmission Cost Recovery Factors (TCRF)).

(5) TSPs shall file reports that will permit the commission to monitor their transmission costs and revenues, in accordance with any filing requirements and schedules prescribed by the commission.

§25.193. Distribution Service Provider Transmission Cost Recovery Factors (TCRF).

(a) **Application.** The provisions of this section apply to all investor-owned distribution service providers (DSPs) providing distribution service within the Electric Reliability Council of Texas (ERCOT) region to retail electric providers and other customers of the distribution system.

(b) **TCRF authorized.** A distribution service provider subject to this section that is billed for transmission service by a transmission service provider (TSP) pursuant to §25.192 of this title (relating to Transmission Service Rates) shall be allowed to include within its tariff a TCRF clause which authorizes the distribution service provider to charge or credit its customer for the cost of wholesale transmission cost changes approved or allowed by the commission service to the extent that such costs vary from the transmission service cost utilized to fix the rates of the distribution provider. The DSP may only update its TCRF twice a year on March 1 and September 1 of each year to pass through the wholesale transmission cost changes billed for by a TSP. The terms and conditions of such TCRF clause shall be approved by an order of the commission. Compliance tariffs shall be filed with the commission 30 days after the approval of this section.

(c) **TCRF Formula.** The TCRF for each class shall be computed pursuant to the following formula:

<table>
<tr><td colspan="2">$$\frac{(NWTR*NL - BWTR*BL) *ALLOC}{BD}$$</td></tr>
<tr><td rowspan="6">Where:</td><td>NWTR is the new wholesale transmission rate approved by the commission by order or pursuant to commission rules;</td></tr>
<tr><td>BWTR is the base wholesale transmission rate used to develop the retail transmission charge in the distribution service provider's last rate case;</td></tr>
<tr><td>NL is the distribution service provider's load based on the 4CP information used to develop the NWTR, and is from the previous calendar year;</td></tr>
<tr><td>BL is the distribution service provider's load based on the 4 CP information used to develop the BWTR in the distribution service provider's last rate case.</td></tr>
<tr><td>ALLOC is the class allocator approved by the commission to allocate the transmission revenue requirement among classes in the distribution service provider's last rate case, unless otherwise ordered by the commission; and,</td></tr>
<tr><td>BD is each class' annual billing determinant (kWh, or kW, or kVa) for the previous calendar year.</td></tr>
</table>

(d) **TCRF charges**. A DSP's TCRF charge shall remain in effect until adjusted under this section or its delivery rates change, following a rate proceeding that it or the commission initiates.

(e) **Reports.** The distribution service provider shall maintain and provide to the commission, semi-annual reports containing all information required to monitor the costs recovered through the TCRF clause. This information includes, but is not limited to, the total estimated TCRF cost for each month, the actual TCRF cost on a cumulative basis, and total revenues resulting from the TCRF. The reports will be filed on March 31 and September 30 of each year.

§25.195. Terms and Conditions for Transmission Service.

(a) **Transmission service requirements.** As a condition to obtaining transmission service, a transmission service customer that owns electrical facilities in the Electric Reliability Council of Texas (ERCOT) region shall execute interconnection agreements with the transmission service providers (TSP) to which it is physically connected. The commission-approved standard generation interconnection agreement (SGIA) for the interconnection of new generating facilities shall be used by power generation companies, exempt wholesale generators, and TSPs. A standard agreement may be modified by mutual agreement of the parties to address specific facts presented by a particular interconnection request as long as the modifications do not frustrate the goal of expeditious, non-discriminatory interconnection and are not otherwise inconsistent with the principles underlying the SGIA.

(b) **Transmission service provider responsibilities.** The TSP will plan, construct, operate and maintain its transmission system in accordance with good utility practice in order to provide transmission service customers with transmission service over its transmission system in accordance with Division 1 of this subchapter (relating to Open-Access

Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas). The TSP shall, consistent with good utility practice, endeavor to construct and place into service sufficient transmission capacity to ensure adequacy and reliability of the network to deliver power to transmission service customer loads. The TSP will plan, construct, operate and maintain facilities that are needed to relieve transmission constraints, as recommended by ERCOT and approved by the commission, in accordance with Division 1 of this subchapter. The construction of facilities requiring commission issuance of a certificate of convenience and necessity is subject to such commission approval.

(c) **Construction of new facilities.** If additional transmission facilities or interconnections between TSPs are needed to provide transmission service pursuant to a request for such service, the TSPs where the constraint exists shall construct or acquire the facilities necessary to permit the transmission service to be provided in accordance with good utility practice, unless ERCOT identifies an alternative means of providing the transmission service that is less costly, operationally sound, and relieves the transmission constraint at least as effectively as would additional transmission facilities.

(1) When an eligible transmission service customer requests transmission service for a new generating source that is planned to be interconnected with a TSP's transmission network, the transmission service customer shall be responsible for the cost of installing step-up transformers to transform the output of the generator to a transmission voltage level and protective devices at the point of interconnection capable of electrically isolating the generating source owned by

the transmission service customer. The TSP shall be responsible, pursuant to paragraph (2) of this subsection, for the cost of installing any other interconnection facilities that are designed to operate at a transmission voltage level and any other upgrades on its transmission system that may be necessary to accommodate the requested transmission service.

(A) An affected TSP may require the transmission service customer to pay a reasonable deposit or provide another means of security, to cover the costs of planning, licensing, and constructing any new transmission facilities that will be required in order to provide the requested service.

(B) If the new generating source is completed and the transmission service customer begins to take the requested transmission service, the TSP shall return the deposit or security to the transmission service customer. If the new generating source is not completed and new transmission facilities are not required, the TSP may retain as much of the deposit or security as is required to cover the costs it incurred in planning, licensing, and construction activities related to the planned new transmission facilities. Any repayment of a cash deposit shall include interest at a commercially reasonable rate based on that portion of the deposit being returned.

(2) A transmission service customer that is requesting transmission service, including transmission service at distribution voltage, may be required to make a contribution in aid of construction to cover all or part of the cost of acquiring or constructing additional facilities, if the acquisition of the additional facilities

would impair the tax-exempt status of obligations issued by the provider of transmission services.

(d) **Curtailment of service.** In an emergency situation, as determined by ERCOT and at its direction, TSPs may interrupt transmission service on a non-discriminatory basis, if necessary, to preserve the stability of the transmission network and service to customers. Such curtailments shall be carried out in accordance with §25.200 of this title (relating to Load Shedding, Curtailments, and Redispatch) and in accordance with ERCOT protocols.

(e) **Filing of contracts.** Electric utilities shall file with the commission all new interconnection agreements within 30 days of their execution, including a cover letter explaining any deviations from the SGIA. These interconnection agreements shall be filed for the commission's information. Interconnection agreements are subject to commission review and approval upon request by any party to the agreement. Upon showing a good cause, appropriate portions of the filings required under this subsection may be subject to provisions of confidentiality to protect competitively sensitive commercial or financial information.

§25.196. Standards of Conduct.

(a) **Applicability.** This section applies to transmission service provider (TSP), as defined in §25.5 (relating to Definitions), that:

(1) is not required by the Public Utility Regulatory Act (PURA) §39.051 to unbundle generation and transmission activities; and

(2) has retail sales of total metered electric energy for the average of the three most recent calendar years that is greater than 6,000,000 megawatt hours.

(b) **Standards of conduct.** Each TSP subject to this section shall comply with the following standards:

(1) The employees of a TSP who are engaged in wholesale merchant functions (that is, the purchase or sale of electric energy at wholesale), other than purchases required under the Public Utility Regulatory Policies Act, shall not:

(A) conduct transmission system operations or reliability functions;

(B) have preferential access to the TSP's system control center and other facilities, beyond the access that is available to other market participants; or

(C) have preferential access to information about the TSP's transmission system that is not available to users of the electronic information network established in accordance with Division 1 of this subchapter.

(2) To the maximum extent practicable, employees of a TSP engaged in transmission system operations must function independently of employees engaged in wholesale merchant functions of the TSP. Employees engaged in transmission system operations may disclose information to employees of the TSP, or of an affiliate, who are engaged in wholesale merchant functions only through the electronic information network, if the information relates to the TSP's

transmission system or offerings of ancillary services, including calculations of available transmission capacity and information concerning curtailments. Employees engaged in transmission system operations may not disclose to employees of the TSP, or of an affiliate, who are engaged in wholesale merchant functions, any information that is not publicly available concerning activities of any competitors of the TSP or any of its affiliates including requests for interconnection by a transmission service customer or requests by the Electric Reliability Council of Texas (ERCOT) for comments on the scope of a system security screening study.

(3) Information concerning transfers of persons between an organizational unit that is responsible for transmission system operations and a unit that is responsible for wholesale merchant functions shall be provided to the commission on a monthly basis and shall be made available, on request, to any market participant.

(4) If an employee of a TSP discloses or obtains information in a manner that is inconsistent with the requirements in this subsection, the TSP shall post a notice and details of the disclosure on the information network.

(5) Employees of a TSP engaged in transmission operations shall apply the rules in Division 1 of this subchapter and any tariffs relating to transmission service in a fair and impartial manner.

(6) Provisions of this section that allow no discretion shall be strictly applied, and where discretion is allowed, it shall be exercised in a non-discriminatory manner.

(7) This subsection shall not apply to data that do not relate to transmission service operations such as information on human resource policies.

§25.198. Initiating Transmission Service.

(a) **Initiating service.** Where a transmission service customer uses the transmission facilities in the Electric Reliability Council of Texas (ERCOT), whether its own facilities or those of another transmission service provider (TSP), to serve load or to make sales of energy to a third party, it shall apply for transmission service pursuant to this section, the ERCOT protocols, and commission-approved tariffs.

(b) **Conditions precedent for receiving service.** Subject to the terms and conditions of this section and in accordance with the ERCOT protocols and commission-approved tariffs, the TSP will provide transmission service to any transmission service customer as that term is defined in §25.5 of this title (relating to Definitions), provided that:

(1) the transmission service customer has complied with the applicable provisions of the ERCOT protocols;

(2) the transmission service customer and the TSP have completed the technical arrangements set forth in subsection (e) of this section; and

(3) if the transmission service customer operates electrical facilities that are interconnected to the facilities of a TSP, it has executed an interconnection agreement for service under this section or requested in writing that the TSP file a proposed unexecuted agreement with the commission.

(c) **Procedures for initiating transmission service.** A transmission service customer requesting transmission service under this section must comply with the ERCOT protocols and commission-approved tariffs.

(1) The transmission service customer shall provide all information deemed necessary by ERCOT to evaluate the transmission service.

(2) ERCOT must acknowledge the request within ten days of receipt. When the request is complete, the acknowledgment must include a date by which a response will be sent to the transmission service customer and a statement of any fees associated with responding to the request (*e.g.*, system studies).

(3) If a transmission service customer fails to provide ERCOT with all information deemed necessary, then ERCOT shall notify the transmission service customer requesting service within 15 business days of receipt and specify the reasons for such failure. Wherever possible, ERCOT will attempt to remedy deficiencies in the application through informal communications with a transmission service customer.

(4) If ERCOT determines that a system security screening study is required, upon approval of the requesting transmission service customer, ERCOT will initiate such a study. If this study concludes that the transmission system is adequate to accommodate the request for service, either in whole or in part, or that no costs are likely to be incurred for new transmission facilities or upgrades, the transmission service will be initiated or tendered, within 15 business days of completion of the system security screening study.

(5) If ERCOT determines as a result of the system security screening study that additions or upgrades to the transmission system are needed to supply the transmission service customer's forecasted transmission requirements, the TSP will, upon the approval of the requesting transmission service customer, initiate a facilities study. When completed, a facilities study will include an estimate of the cost of any required facilities or upgrades and the time required to complete such construction and initiate the requested service.

(6) When a transmission service customer requests transmission service for a new resource under this section, ERCOT shall establish the scope of any system security screening study. The study will be used to determine the feasibility of integrating such new resource into the TSPs' transmission system, and whether any upgrades of facilities providing transmission are needed. ERCOT will perform the system security screening study.

(A) ERCOT shall complete the system security screening study and provide the results to the transmission service customer within 90 days after the receipt of an executed study agreement and receipt from the transmission service customer of all the data necessary to complete the study. In the event ERCOT is unable to complete the study within the 90-day period, it will provide the transmission service customer a written explanation of when the study will be completed and the reasons for the delay.

(B) The requesting transmission service customer shall be responsible for the cost of the system security screening study and shall be provided with the results thereof, including relevant work papers to the extent such results and workpapers do not contain protected competitive information as reasonably determined by ERCOT.

(C) ERCOT will use a methodology consistent with good utility practice to conduct the system security screening study and shall coordinate with affected TSPs as needed in determining the most efficient means for all TSPs in the ERCOT region to assure feasibility of transmission service.

(d) **Facilities study.** Based on the results of the system security screening study, the TSP shall perform, pursuant to an executed facilities study agreement with the transmission service customer, a facilities study addressing the detailed engineering, design and cost of transmission facilities required to provide the requested transmission service.

(1) The facilities study will be completed as soon as reasonably practicable. If the TSP may charge a contribution in aid of construction under §25.195 of this title (relating to Terms and Conditions for Transmission Service), the TSP shall notify the transmission service customer whether it considers that a contribution in aid of construction is appropriate and the amount of the contribution. The TSP shall base its request on the information in the system security screening study, the facilities study, good utility practice, and §25.195 of this title.

(2) The transmission service customer shall be responsible for the reasonable cost of the facilities study pursuant to the terms of the facilities study agreement and shall be provided with the results of the facility study, including relevant workpapers.

(3) Pursuant to §25.195(c)(2) of this title, the TSP shall be responsible for the costs of any planning, designing, and constructing of facilities of the TSP associated with its addition of new facilities used to provide transmission service.

(e) **Technical arrangements to be completed prior to commencement of service.** Service under this section shall not commence until the installation has been completed of all equipment specified under the interconnection agreement, consistent with guidelines adopted by the national reliability organization and ERCOT, except that the TSP shall provide the requested transmission service, to the extent that such service does not impair the reliability of other transmission service. The TSP shall exercise reasonable efforts, in coordination with the transmission service customer, to complete such arrangements as soon as practical prior to the service commencement date.

(f) **Transmission service customer facilities.** The provision of transmission service shall be conditioned upon the transmission service customer's constructing, maintaining and operating the facilities on its side of each point of interconnection that are necessary to reliably interconnect and deliver power from a resource to the transmission system and from the transmission system to the transmission service customer's loads.

(g) **Transmission arrangements for resources located outside of the ERCOT region.** If a transmission service customer intends to import power from outside the ERCOT region, it shall make any transmission arrangements necessary for delivery of capacity and energy from the resource to an interconnection with ERCOT.

(h) **Changes in service requests.** A transmission service customer's decision to cancel or delay the addition of a new resource shall not relieve the transmission service customer of the obligation to pay for any study conducted in accordance with this section.

(i) **Annual load and resource information updates.** A transmission service customer shall provide ERCOT with annual updates of load and resource forecasts for the following five-year period. The transmission service customer also shall provide ERCOT with timely written notice of material changes in any other information provided in its application relating to the transmission service customer's load, resources, or other aspects of its facilities or operations affecting the TSP's ability to provide reliable service under Division 1 of this subchapter.

(j) **Termination of transmission service.** A transmission service customer may terminate transmission service after providing ERCOT and the appropriate TSP with written notice of its intention to terminate. A transmission service customer's provision of notice to terminate service under this section shall not relieve the transmission service customer of its obligation to pay TSPs any rates, charges, or fees, including contributions in aid of construction, for service previously provided under the applicable interconnection service agreement, and which are owed to TSPs as of the date of termination.

§25.200. Load Shedding, Curtailments, and Redispatch.

(a) **Procedures.** The Electric Reliability Council of Texas (ERCOT) shall direct non-discriminatory emergency load shedding and curtailment procedures for responding to emergencies on the transmission system in accordance with ERCOT protocols.

(b) **Congestion management principles.** ERCOT shall develop and implement market mechanisms to manage transmission congestion in accordance with ERCOT protocols.

(c) **Transmission constraints.** During any period when ERCOT determines that a transmission constraint exists on the transmission system, and such constraint may impair the reliability of a transmission service provider's (TSP's) system or adversely affect the operations of either a TSP or a transmission service customer, ERCOT will take actions, consistent with good utility practice and the ERCOT protocols, that are reasonably necessary to maintain the reliability of the TSP's system and avoid interruption of service. ERCOT shall notify affected TSPs and transmission service customers of the actions being taken. In these circumstances, TSPs and transmission service customers shall take such action as ERCOT directs.

(1) Service to all transmission service customers shall be restored as quickly as reasonably possible.

(2) To the extent ERCOT determines that the reliability of the transmission system can be maintained by redispatching resources, or when redispatch arrangements

are necessary to facilitate generation and transmission transactions for a transmission service customer, a transmission service customer will initiate procedures to redispatch resources, as directed by ERCOT.

(3) To the greatest extent possible, any redispatch shall be made on a least-cost non-discriminatory basis. Except in emergency situations, any redispatch under this section will provide for equal treatment among transmission service customers.

(4) ERCOT shall keep records of the circumstances requiring redispatch and the costs associated with each redispatch and file annual reports with the commission, describing costs, frequency and causes of redispatch. Costs for relieving capacity constraints shall be allocated in a manner consistent with the ERCOT protocols.

(d) **System reliability.** Notwithstanding any other provisions of this section, a TSP may, consistent with good utility practice and on a non-discriminatory basis, interrupt transmission service for the purpose of making necessary adjustments to, changes in, or repairs to its lines, substations and other facilities, or where the continuance of transmission service would endanger persons or property. In exercising this power, a TSP's liability shall be governed by §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities). In addition, notwithstanding any other provisions of this section, ERCOT may cause the interruption of transmission service for the purpose of maintaining ERCOT system stability and safety. In exercising this power, ERCOT shall not be liable for its ordinary negligence but may be liable for its gross negligence or intentional misconduct when legally due.

(1) In the event of any adverse condition or disturbance on the TSP's system or on any other system directly or indirectly interconnected with the TSP's system, the TSP, consistent with good utility practice, may interrupt transmission service on a non-discriminatory basis in order to limit the extent of damage from the adverse condition or disturbance, to prevent damage to generating or transmission facilities, or to expedite restoration of service. The TSP shall consult with ERCOT concerning any interruption in service, unless an emergency situation makes such consultation impracticable.

(2) The TSP will give ERCOT, affected transmission service customers, and affected suppliers of generation as much advance notice as is practicable in the event of an interruption.

(3) If a transmission service customer fails to respond to established emergency load shedding and curtailment procedures to relieve emergencies on the transmission system, the transmission service customer shall be deemed to be in default. Any dispute over a transmission service customer's default shall be referred to alternative dispute resolution under §25.203 (relating to Alternative Dispute Resolution (ADR)) and may subject the transmission service customer to an assessment of an administrative penalty by the commission under Public Utility Regulatory Act §15.023.

(4) ERCOT shall report interruptions to the commission, together with a description of the events leading to each interruption, the services interrupted, the duration of the interruption, and the steps taken to restore service.

(e) **Transition provision on priority for transmission service and ancillary services.** Subsection (b) of this section is effective upon implementation of a single control area in the ERCOT region. Until that date, the current rules for priority of planned transmission service will continue, as provided by this subsection.

(1) Any redispatch under this section will provide for equal treatment among transmission service customers, subject to the priorities set out by this paragraph. Planned transmission service shall have priority over unplanned transmission service, and annual planned transmission service shall have priority over planned transmission service of a shorter duration.

(A) Subject to the foregoing priorities, for applications for planned or unplanned transmission service, complete applications filed earlier with the independent system operator shall have priority over applications that are filed later. Timely requests for annual planned transmission service will be accorded equal priority.

(B) Where a transmission service customer is using annual planned transmission service for a resource that becomes unavailable due to an unplanned outage or the expiration of a power supply contract, the transmission service customer shall have priority, in using the same transmission capacity to transmit power from a replacement resource, over other requests for unplanned transmission service or planned transmission service of a shorter duration.

(2) The price for redispatch services for annual planned transactions shall be based on the cost of providing the service, which shall be allocated among transmission

service customers in proportion to each customer's share of the transmission cost of service, as determined by the commission under §25.192 of this title (relating to Transmission Service Rates). For redispatch required to accommodate an annual planned transaction, the electric utility providing the redispatch service shall provide information documenting the costs incurred to provide the service to the independent system operator. This information shall be available to affected persons.

(3) The cost of redispatch services for other transactions (including planned transmission service of a duration of less than a year) shall be borne by the transmission service customer for whose benefit the redispatch is made. Electric utilities shall provide binding advance bids for redispatch services for unplanned transactions. The participants in unplanned transactions shall be promptly notified by the independent system operator that their transactions may be or have been continued through redispatch; shall be informed of the cost of the redispatch measures; and shall have the opportunity to abandon or curtail their transactions to avoid additional redispatch costs.

(4) Electric utilities that have tariffs for ancillary services on the effective date of this section shall continue to provide services under those tariffs until ERCOT implements a single control area in the ERCOT region.

(5) The following words and terms, when used in this subsection, shall have the following meanings unless the context indicates otherwise:

(A) Planned resources — Generation resources owned, controlled, or purchased by a transmission customer, and designated as planned resources for the purpose of serving load.

(B) Planned transmission service — A service that permits a transmission service customer to use the transmission service providers' transmission systems for the delivery of power from planned resources to loads on the same basis as the transmission service providers use their transmission systems to reliably serve their native load customers.

(C) Unplanned transmission service — A service that permits a transmission service customer to use the transmission service providers' transmission systems to deliver energy to its loads from resources that have not been designated as the transmission service customer's planned resources.

§25.202. Commercial Terms for Transmission Service.

(a) **Billing and payment.** Within a reasonable time after the first day of each month, transmission service providers (TSPs) shall issue invoices for the prior month's transmission service to distribution service providers (DSPs) and customers responsible for the export of power from the Electric Reliability Council of Texas (ERCOT) region.

(1) An invoice for transmission service shall be paid so that the TSP will receive the funds by the 35th calendar day after the date of issuance of the invoice, unless the

TSP and the transmission service customer agree on another mutually acceptable deadline. All payments shall be made in immediately available funds payable to the TSP, or by wire transfer to a bank named by the service provider or by other mutually acceptable terms.

(2) Interest on any unpaid amount shall be calculated by using the interest rate applicable to overbillings and underbillings, set by the commission, and compounded monthly. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the TSP.

(3) In the event the transmission service customer fails, for any reason other than a billing dispute as described in subparagraph (A) of this paragraph, to make payment to the TSP on or before the due date, and such failure of payment is not corrected within 30 calendar days after the TSP notifies the customer to cure such failure, the customer shall be deemed to be in default.

(A) Upon the occurrence of a default, the TSP may initiate a proceeding with the commission to terminate service. If the commission finds that a default has occurred, the transmission service customer shall pay to the TSP an amount equal to two times the amount of the payment that the customer failed to pay, in addition to any other remedy ordered by the commission. In the event of a billing dispute between the TSP and the transmission service customer, the TSP will continue to provide service during the pendency of the proceeding, as long as the customer:

(i) continues to make all payments not in dispute; and

(ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute.

(B) If the transmission service customer fails to meet the requirements in subparagraph (A) of this paragraph, then the TSP will provide notice to the customer and to the commission of its intention to terminate service.

(C) Any dispute arising in connection with the termination or proposed termination of service shall be referred to the alternative dispute resolution process described in §25.203 of this title (relating to Alternative Dispute Resolution (ADR)).

(b) **Indemnification and liability.**

(1) Neither a transmission service customer nor TSP shall be liable to the other for damages for any act that is beyond such party's control, including any event that is a result of 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, a curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities, or by the making of necessary repairs upon the property or equipment of either party.

(2) Notwithstanding the provisions of paragraph (1) of this subsection, a transmission service customer and TSP shall assume all liability for, and shall indemnify each other for, any losses resulting from negligence or other fault in the design, construction, or operation of their respective facilities. Such liability shall include a transmission service customer or TSP's monetary losses, costs and expenses of

defending an action or claim made by a third person, payments for damages related to the death or injury of any person, damage to the property of the TSP or transmission service customer, and payments for damages to the property of a third person, and damages for the disruption of the business of a third person. This paragraph does not create a liability on the part of a TSP or transmission service customer to a retail customer or other third person, but requires indemnification where such liability exists. The indemnification required under this paragraph does not include responsibility for the TSP's or transmission service customer's costs and expenses of prosecuting or defending an action or claim against the other, or damages for the disruption of the business of the service provider or customer. The limitations on liability set forth in this subsection do not apply in cases of gross negligence or intentional wrongdoing.

(c) **Creditworthiness for transmission service.** For the purpose of determining the ability of a transmission service customer to meet its obligations related to transmission and any other obligation in Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas), a TSP may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices.

(1) The TSP may require a transmission service customer to provide and maintain in effect during the term of service, an unconditional and irrevocable letter of credit in a reasonable amount as security to meet its responsibilities and obligations under Division 1 of this subchapter or an alternative form of security proposed by

the customer and acceptable to the service provider and consistent with commercial practices established by the Uniform Commercial Code that reasonably protects the TSP against the risk of non-payment. Credit worthiness standards must be applied to all transmission service customers on a non-discriminatory basis.

(2) If a transmission service customer is creditworthy, no letter of credit or alternative form of security shall be required.

§25.203. Alternative Dispute Resolution (ADR).

(a) **Obligation to use alternative dispute resolution.** Subject to the right to seek direct commission review pursuant to subsection (f) of this section, in the event that a dispute arises under Division 1 of this subchapter (relating to Open-Access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas) and the dispute is not subject to the alternative dispute resolution procedures established in the commission-approved Electric Reliability Council of Texas (ERCOT) protocols, the parties to the dispute shall engage in mediation or other alternative means for resolving the dispute, prior to filing a complaint with the commission.

(b) **Referral to senior representatives.** Such disputes shall be referred for resolution to a designated senior representative of each of the parties to the dispute. The senior dispute representative shall be an individual who has authority to resolve the dispute. The senior dispute representatives shall make a good faith effort to resolve the dispute on an informal basis as promptly as practicable.

(c) **Mediation or arbitration.** In the event the parties are unable to resolve the dispute under subsection (b) of this section, the parties shall either:

(1) refer the matter to arbitration in accordance with procedures in subsection (d) of this section; or

(2) upon agreement of all parties, engage in mediation with the assistance of a neutral third party, mutually selected by all parties concerned, who has training or experience in mediation.

(d) **Arbitration.** If the parties choose to refer the matter to arbitration, pursuant to subsection (c) of this section:

(1) The commission shall maintain a commission-approved list of qualified persons available to serve on arbitration panels who are knowledgeable in electric utility matters, including electricity transmission and bulk power issues. The commission shall also maintain a separate list of qualified persons experienced in arbitration that may be available to chair the arbitration panels.

(2) A party shall initiate arbitration by filing a letter with the commission requesting that arbitration be scheduled. A copy of the letter shall be served upon the other party to the dispute at the same time the letter is filed with the commission.

(3) Only parties to the dispute may participate in the arbitration.

(4) **Arbitration panel.** Any arbitration initiated under this section shall be conducted before a three-member arbitration panel. Each party shall choose one arbitrator from the commission-approved list of panel members. In the event there are more than two parties to the dispute, the parties shall jointly select the two arbitrators. The two arbitrators chosen by the parties shall choose the chairman of the arbitration panel. If the two arbitrators chosen by the parties are unable to agree on the selection of a chairman, they will be dismissed and the parties shall select two different arbitrators from the approved list. The arbitrators are not required to choose the chairman from the names of persons on the commission's list of panel members so long as the person chosen is qualified as an arbitrator. Panel members chosen shall not have any current or past substantial business or financial relationships with any party to the arbitration (other than previous arbitration experience). The chairman of the panel shall make all necessary arrangements for arbitration to commence within ten working days of completion of the panel.

(5) **Procedures.** 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 Commercial Arbitration Rules of the American Arbitration Association and any applicable commission rules. The panel may request that the parties provide additional technical information relevant to the dispute. The arbitration panel shall render a decision within 30 calendar days from the closing of the evidentiary record of the arbitration and shall notify the

parties in writing of such decision and the reasons therefore. The decision shall not be considered precedent in any future proceeding.

(6) **Basis for decision.** The arbitrators shall be authorized only to interpret and apply the provisions of the commission's rules relating to transmission services, the commission-approved ERCOT protocols, the transmission service provider's (TSP) transmission tariff, and any service agreement entered into under that tariff. The arbitrators shall have no power to modify or change any of the above in any manner. The arbitrators may agree with the positions of one or more of the parties, or may recommend a compromise position.

(7) If any party to the arbitration files a complaint before the commission, the arbitration panel decision shall be filed in the commission's Central Records and shall be considered by the commission in preparing a Preliminary Order in the complaint proceeding. The complaint shall be docketed and may be referred to the State Office of Administrative Hearings. The decision may be admitted in evidence in any such complaint proceeding.

(8) **Costs.** Each party shall be responsible for the following costs, if applicable:

(A) its own costs incurred during the arbitration process;

(B) its pro rata share of the costs of the three arbitrators, pooled and shared evenly among the parties.

(e) **Effect of pending alternative dispute resolution.** The transaction which is the subject of the dispute shall be allowed to go forward pending the resolution of the dispute to the extent system reliability is not affected.

(f) **Effect on rights under law.** Nothing in this section shall restrict the rights of any party to file a complaint with the commission under relevant provisions of the Public Utility Regulatory Act or with the Federal Energy Regulatory Commission under the Federal Power Act or the right of a TSP to seek changes in the rates or terms for transmission, following the completion of the alternative dispute resolution procedures in this section.

(1) Use or application of the arbitration provisions in this subsection does not affect the jurisdiction of the commission over any matters arising under this section.

(2) Nothing in this section shall restrict the right of a market participant to file a petition seeking direct relief from the commission without first utilizing the alternative dispute resolution process where an action by a TSP, distribution service provider (DSP), or ERCOT might inhibit the ability of a transmission service customer to provide continuous and adequate service to its customers.

(3) Because of the imminent threat to the health and welfare of a TSP's customers in the event of a reliability problem, a petitioner's dispute will be heard by the commission in an emergency session except in those instances where a quorum of the commission is not present. In those instances where a quorum is not present, the chairman of the commission shall have the authority to issue an interim order to resolve the dispute so as to protect the reliability of the system, with the order remaining in effect until such time as a quorum is present.

PROPOSED REPEALS:

§25.193. Procedures for Modifying Transmission Rates.

§25.194. Determining Peak Load and Transmission Adequacy.

§25.197. ERCOT Independent System Operator.

§25.201. Ancillary Services.

§25.204. Summary of Required Filings.

SUBCHAPTER O. UNBUNDLING AND MARKET POWER

DIVISION 2. Independent Organizations.

§25.361. Electric Reliability Council of Texas (ERCOT).

(a) **Applicability.** This section applies to the Electric Reliability Council of Texas (ERCOT). It also applies to transmission service providers (TSPs) and transmission service customers, as defined in §25.5 of this title (relating to Definitions), with respect to interactions with ERCOT.

(b) **Purpose.** ERCOT shall perform the functions of an independent organization under the Public Utility Regulatory Act (PURA) §39.151 to ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; ensure the reliability and adequacy of the regional electrical network; ensure that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to the persons who need that information; and ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region. In addition, ERCOT may, on the introduction of customer choice in the ERCOT power region, acquire generation-related ancillary services on a nondiscriminatory basis on behalf of entities selling electricity at retail in accordance with PURA §35.004(e).

(c) **Functions.** ERCOT shall operate an integrated electronic transmission information network and carry out the other functions prescribed by this section. ERCOT shall:

(1) administer, on a daily basis, the operational and market functions of the ERCOT system, including scheduling of resources and loads, and transmission congestion management, as set forth in the ERCOT protocols;

(2) serve as the single point of contact for the initiation of transmission transactions;

(3) maintain the reliability and security of the ERCOT region's electrical network, including the instantaneous balancing of ERCOT generation and load and monitoring the adequacy of resources to meet demand;

(4) direct the curtailment and redispatch of ERCOT generation and transmission transactions on a non-discriminatory basis, consistent with ERCOT protocols;

(5) accept and supervise the processing of all requests for interconnection to the ERCOT transmission system from owners of new generating facilities;

(6) coordinate and schedule planned transmission facility outages;

(7) perform system screening security studies, with the assistance of affected TSPs;

(8) plan the ERCOT transmission system, in accordance with subsection (f) of this section;

(9) administer registration procedures for market participants;

(10) administer the renewable energy program;

(11) monitor generation planned outages;

(12) submit an annual report to the commission identifying existing and potential transmission and distribution constraints and system needs within ERCOT, alternatives for meeting system needs, and recommendations for meeting system

needs, pursuant to PURA §39.155 (relating to Commission Assessment of Market Power); and

(13) perform any additional duties required under the ERCOT protocols.

(d) **Commercial functions.** ERCOT shall dispatch generation facilities only in accordance with the provisions of the ERCOT protocols. This responsibility includes authority to redispatch generation resources, in accordance with §25.200 of this title (relating to Load Shedding, Curtailments, and Redispatch) and the ERCOT protocols, and to determine and purchase the amount of ancillary services required to maintain and ensure the reliability of the network. All commercial functions required to ensure reliability and adequacy of the transmission network are to be conducted in accordance with the ERCOT protocols.

(e) **Liability**. ERCOT shall not be liable in damages for any act or event that is beyond its control and which could not be reasonably anticipated and prevented through the use of reasonable measures, including, but not limited to, an act of God, act of the public enemy, war, insurrection, riot, fire, explosion, labor disturbance or strike, wildlife, unavoidable accident, equipment or material shortage, breakdown or accident to machinery or equipment, or good faith compliance with a then valid curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities.

(f) **Planning.** ERCOT shall conduct transmission system planning and exercise comprehensive authority over the planning of bulk transmission projects that affect the transfer capability of the ERCOT transmission system. ERCOT shall supervise and coordinate the other planning activities of TSPs.

(1) ERCOT shall evaluate and make a recommendation to the commission as to the need for any transmission facility over which it has comprehensive transmission planning authority.

(2) A TSP shall coordinate its transmission planning efforts with those of other TSPs, insofar as its transmission plans affect other TSPs.

(3) ERCOT shall submit to the commission any revisions or additions to the planning guidelines and procedures prior to adoption. ERCOT may seek input from the commission as to the content and implementation of its guidelines and procedures as it deems necessary.

(g) **Information and coordination.** Transmission service providers and transmission service customers shall provide such information as may be required by ERCOT to carry out the functions prescribed by this section and the ERCOT protocols. ERCOT shall maintain the confidentiality of competitively sensitive information entrusted to it. ERCOT shall also disseminate information relating to market prices and the availability of services, in accordance with the ERCOT protocols. Providers of transmission and ancillary services shall also maintain the confidentiality of competitively sensitive information entrusted to them by ERCOT or a transmission service customer.

(h) **Interconnection standards.** In performing its functions related to the reliability and security of the ERCOT electrical network, ERCOT may prescribe reliability and security standards for the interconnection of generating facilities that use the ERCOT transmission network. Such standards shall not adversely affect or impede manufacturing or other internal process operations associated with such generating facilities, except to the minimum extent necessary to assure reliability of the ERCOT transmission network.

(i) **ERCOT administrative fee.** ERCOT shall charge an administrative fee for transmission service in accordance with ERCOT protocols. Changes in the fee or application of new fees are subject to commission approval.

(j) **Reports.** Each TSP and transmission service customer in the ERCOT region shall on an annual basis provide historical information concerning peak loads and resources connected to the TSP's system. ERCOT shall periodically file with the commission reports concerning its governance, operations and budget, the reliability region of the ERCOT electrical network, and ERCOT's transmission planning efforts, including a list of any transmission projects that it recommends.

(k) **Anti-trust laws.** The existence of ERCOT is not intended to affect the application of any state or federal anti-trust laws.

This agency hereby certifies that the rules, as adopted, have been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that amended §§25.5, 25.191, 25.192, new §25.193, amended §§25.195, 25.196, 25.198, 25.200, 25.202, 25.203, and new §25.361 are hereby adopted with changes to the text as proposed; and the repeals of existing §§25.193, 25.194, 25.197, 25.201 and 25.204 are hereby adopted with no changes as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 25th DAY OF MAY 2001.

PUBLIC UTILITY COMMISSION OF TEXAS

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Chairman Pat Wood, III

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Commissioner Brett A. Perlman