The Public Utility Commission of Texas (commission) adopts new §25.341, relating to Definitions; new §25.342, relating to Electric Business Separation; new §25.343, relating to Competitive Energy Services; new §25.344, relating to Cost Separation Proceedings; new §25.345, relating to Recovery of Stranded Costs Through Competition Transition Charge; and new §25.346, relating to Separation of Electric Utility Metering and Billing Costs and Activities with changes to the proposed text as published in the September 10, 1999 *Texas Register* (24 TexReg 7099). These new sections are adopted under Project Number 21083.

Project Number 21083, *Cost Unbundling and Separation of Utility Business Activities, Including Separation of Competitive Energy Services and Distributive Generation* was established July 7, 1999. Informal task force meetings and workshops with commission staff and interested parties were conducted during July and August.

Senate Bill 7 (SB7), Act of May 27, 1999, 76th Legislature, Regular Session, chapter 405, 1999 Texas Session Law Service 2543 (Vernon) which amends several sections of the Public Utility Regulatory Act (PURA) was passed by the 76th Texas Legislature and is effective September 1, 1999. The Legislature determined that the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that, except for transmission and distribution (T&D) services and for the recovery of stranded costs, electric services and their prices should be determined by customer choices and the normal forces of competition. The Legislature enacted PURA Chapter

39 to protect the public interest during the transition to and in the establishment of a fully competitive electric power industry.

The electric industry will be in a period of transition to competition until January 1, 2002, when each electric utility is required by PURA §39.051 to separate its business activities from one another into the following units: a power generation company, a retail electric provider (REP), and a transmission and distribution company. This separation may be accomplished through the creation of separate nonaffiliated companies or separate affiliated companies owned by a common holding company, or through the sale of assets to a third party. On or before September 1, 2000, each electric utility shall separate from its regulated utility activities its customer energy services business activities that are already widely available in the competitive market. By January 10, 2000, utilities are required to file with the commission plans describing how they intend to unbundle their business activities in a manner that provides for a separation of personnel, information flow, functions, and operations. On or before April 1, 2000, each electric utility shall file proposed tariffs for its proposed transmission and distribution utility (T&D utility) pursuant to PURA §39.201. Electric utilities are allowed to recover all of their net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service pursuant to PURA §39.251 through §39.265.

In proposing these rules relating to the unbundling of regulated and non-regulated activities, the commission has four objectives. First, the commission seeks to implement on January 1, 2002, a competitive retail electric market that allows each retail customer to choose the customer's provider of electricity and that encourages full and fair competition among all providers of electricity. Second, the commission will allow utilities with uneconomic generation-related assets and purchased power contracts to recover the reasonable excess costs over market (ECOM) of those assets and purchased power contracts. Third, the commission desires to protect the competitive process in a manner that ensures the confidentiality of competitively sensitive information during the transition to a competitive market and after the commencement of customer choice. Fourth, the commission seeks to prohibit practices between regulated and competitive activities that may unreasonably restrict, impair, or reduce the level of competition during the transitional separation of personnel, information flow, functions, and operations, and after a competitive market is established.

Proposed §25.341 provides definitions for new terms used in Subchapter Q.

Proposed §25.342 implements PURA §39.051 by prescribing the manner by which electric utilities should separate their business into different components.

Proposed §25.343 implements PURA §39.051(a) by prescribing the manner by which an electric utility must separate its competitive energy services.

Proposed §25.344 implements PURA §39.201 by prescribing the manner by which the utility should separate its costs and prepare its transmission and distribution tariffs.

Proposed §25.345 specifies the manner by which utilities with stranded costs may recover stranded costs through the use of a competitive transition charge. The section provides the means for allocating and collecting stranded costs from the utility customers.

Proposed §25.346 implements PURA §39.107 and specifies the billing and metering services an electric utility may offer and the manner in which it may offer such services.

Executive Summary

The major issues raised by this rulemaking are as follows:

I. Corporation separation;

II. Allocation and collection of stranded costs;

III. Class consolidation and rate design for non-bypassable charges;

IV. Separation of competitive energy services;

V. On-site generation exemption;

VI. Transmission and distribution utility's contact with retail customers; and

VII. Rate of Return for transmission and distribution system.

The following is a brief description on how these issues were handled.

I. Corporation separation

The issue of whether utilities are required to create a separate corporation for the separate entities that result from unbundling arose in this rulemaking. Although the commission requested and received briefs on the issue, the commission decided that it needed more information on this. Consequently, this issue will be addressed in the business separation filings rather than by rule.

II. Allocation and collection of stranded costs

There are two types of allocation in question: jurisdictional/wholesale and Texas retail.

Jurisdictional/Wholesale Allocation:

Chapter 39 in PURA provides mechanisms for a utility to recover its retail stranded costs from its retail customers, but the only mention of wholesale stranded costs is PURA §39.265, which states that Subchapter F is not intended to alter the right of a utility to recover stranded costs from wholesale customers. The commission concluded that the decision to recover stranded costs from wholesale customers is an issue to be decided between the utility and the wholesale customers. If they are not able to reach agreement, the issue would be resolved by the commission or by the Federal Energy Regulatory Commission (FERC), for the utilities it has jurisdiction over. But, in any event, the retail customers should be protected from inappropriate shifting of stranded costs from wholesale customers to them.

Texas Retail Allocation:

The parties' comments on the proposed unbundling rule suggested a number of alternatives for the development of the demand allocator for dealing with the initial allocation of stranded costs. Parties also disagree on whether the energy allocator used in the allocation of Texas retail stranded costs should be adjusted for known and measurable changes, such as customer migration, customer departure, and on-site generation exemption. The central issue regarding the allocation of stranded costs is what, if any, adjustments need to be made to the allocators from the utility's last rate order in order to reflect changes in the load characteristics of customer classes.

The parties' comments focus on the interpretation of §39.253 and the legislative history of this provision, but they also identified a number of policy issues that bear on the allocation question. The policy implications of the different approaches to allocating stranded costs vary by rate class and, to some degree, by utility.

The parties have basically argued for the numeric approach or the methodology approach, which may or may not reflect known and measurable adjustments. Other alternatives may be reasonable, recognizing that there is significant uncertainty about matters like the degree of load loss and load shift related to the on-site generation exemption, customer migration, and the response of industrial load to higher wire charges after 2002.

The commission concludes that the cost allocation issues regarding the jurisdictional allocation and the demand allocator used to determine the Texas retail allocation should be addressed on a case by case basis in either the utilities' securitization cases or their April 2000 cases. These allocation issues are policy related, but it is desirable to tailor the allocators to fit each utility's different situation. The particular circumstances of each utility should be examined and used to determine the appropriate allocation methodology for the utility. The commission also concludes that the issue regarding the allocation to the non-firm classes should also be addressed on a case by case basis within each utility's securitization case or April 2000 case.

The commission also concludes that the energy allocator used in the allocation of Texas retail stranded costs should be determined based on the energy consumption for the test year ending May 1, 1999, adjusted only for weather, as prescribed clearly in PURA §39.253(g).

In addition, the commission concludes that the allocation to special rate classes which do not have an allocator in the utility's last cost of service study should be determined based on their generation-related revenue embedded in their total base rate revenue requirement from the utility's last rate case. For the rate classes that have been determined as discounted rate schedules by the commission, the revenue used to determine the allocation for them should include the imputed revenues.

III. Class consolidation and rate design for non-bypassable charges

The prospect of class consolidation drew a fair amount of comment. Some customer groups opposed consolidation of classes because of the disparate effects on customers. Other customer groups suggested principles that should be followed in determining the class consolidation. And many commenters expressed concerns on the bill impacts of class consolidation on existing customer classes, on individual customers, and on the price to beat. Some commenters suggested that there might be different class consolidations before and after the recovery of the competition transition charge (CTC). Many of the commenters maintained that class consolidation should not be expressly defined in this rule, but instead considered in the cost separation proceedings, on a utility-specific basis, in order to recognize differences among utilities.

The question of rate design also raised a number of comments. There were controversies over how non-bypassable charges shall be collected--based on energy or demand--and whether they should be similar to existing rate structure. Some suggested that the rate design of non-bypassable charges should be addressed in the cost separation proceedings, on a utility-specific basis, in order to recognize differences.

The commission believes some degree of class consolidation and a different rate design will be needed to reflect the new competitive paradigm and to foster the development of the competitive market as envisioned by the statute. The commission also agrees with many commenters that there are certain principles that should be followed in determining the class consolidation and rate design. In light of the new competitive environment, some of these principles may be given more consideration than others, such as simplifying billing and easy bill comparison for customers and other market participants. The commission also agrees with some commenters that balancing the benefits of class consolidation and the potential impact on customers should be one of the factors in determining the class consolidation. In particular, during the price to beat period, special attention should be given to the protection of the headroom, and preserving the commission's discretion on the implementation of the price to beat provision of SB 7.

Given the myriad of factors that must be considered in evaluating class consolidation and rate design, the commission concludes that the class consolidation and the rate design of non-bypassable charges should not be expressly defined in this rule, but instead addressed in the cost separation proceedings.

IV. Separation of competitive energy services

These rules address the following two aspects of the issue related to separation of competitive energy services:

(1) The separation plan for competitive energy services; and

(2) Definition of competitive energy service.

The separation plan for competitive energy services

Pursuant to proposed §25.342 and the Business Separation Plan – Filing Package (BSP-FP), on January 10, 2000, each electric utility must file their Electric Business Separation Plan which contains two distinct separation plans:

(1) Separation Plan for Competitive Energy Services effective September 1, 2000, and

(2) Separation Plan of Electric Utility Business Activities effective January 1, 2002.

The separation of all competitive energy services must be completed, including the utility's proposed petitioned services by September 1, 2000, while Part 2 of the separation plan for January 1, 2002 can continue to be modified for commission approval prior to January 1, 2002. It is important to note that the separation plan for competitive energy services will be approved and incorporated into Part 2 of the utility's business separation filing plan for January 1, 2002.

Proposed §25.343 (relating to Competitive Energy Services) prohibits the regulated utility after September 1, 2000 from providing competitive energy services as defined in proposed §25.341(6).

Pursuant to proposed §25.342, the utility must also file its plan for the separation of electric utility business activities into the following units: Power Generation Company (PGC), T&D Utility, and the Retail Electric Provider (REP). The plan also contains its proposed classification of T&D utility services into four service classifications: system services, discretionary services, petitioned services, and other services. The classification for "petitioned services," competitive energy services which are found to not be widely available, will occur before September 1, 2000 pursuant to Part 1 (Section L) of the BSP-FP. Therefore, except for petitioned services, the classification of system, discretionary, and other services will occur as part of the business separation and cost separation proceedings.

Definition of Competitive Energy Services:

The definition of competitive energy services included in §25.341(6) received a large amount of comment, which addressed mostly the question of whether the services included in the list of competitive energy services should be categorized as competitive energy services.

The utilities maintained that the proposed definition inappropriately broadens the required separation of PURA §39.051(a), which requires the separation of only those customer energy services business activities which are "already widely available in the competitive market" by September 1, 2000. The commission believes that the definition of competitive energy services does not go beyond the statutory requirement for separation of competitive energy services. This definition of competitive energy services coupled with the proposed petition process, which allows a utility to provide service not widely available, reasonably implements PURA §39.051(a).

There were a few specific services that were controversial. These include street lighting, security lighting, economic development and community support, and advanced metering services.

Street lighting:

The utilities generally maintained that the provision of street lighting to municipalities and unincorporated communities should be permitted to continue after September 1, 2000 because utilities are obligated under franchise agreements to provide street lighting after September 1, 2000. Furthermore, they pointed to safety and reliability concerns as a reason that they should continue to provide street lighting. Other parties argued that street lighting should be subject to the same standards as other competitive energy services.

The commission believes that street lighting serves an important public safety function for motorists and pedestrians along public roadways and highways. While certain aspects of street lighting service may properly be considered competitive energy services, a separate rulemaking project should be set up to more closely analyze the issues surrounding the procedures for separating street lighting service from the regulated utility and the potential impacts of a separation on affected parties. This rulemaking will be completed prior to January 1, 2002. As a result, no action should be taken at this time to incorporate street lighting service into the definition of competitive energy services.

Non-roadway, outdoor security lighting:

Two utilities commented on the potential cost impact regarding non-roadway, outdoor security lighting separation and the impact of the rate freeze period on security lighting. It was also commented that thousands of security lights would have to be modified to alleviate conflicts between National Electric Safety Code (NESC) standards (under which only utilities are allowed to operate) and the National Electric Code (NEC) standards.

The commission believes that the provision of non-roadway, outdoor security lighting services and the operation, maintenance, and replacement of end-use equipment are competitive energy services. However, the provision of existing tariffed security lighting service is subject to the retail base rate freeze as prescribed by PURA §39.052. In order to reconcile the required separation with the rate freeze, the regulated utility should close its existing security lighting tariffs to new customers on and after September 1, 2000, but continue to provide these services to existing customers during the freeze period. Following the freeze period, such services should be transferred to the utility's affiliated REP or other unregulated affiliates. Prior to the expiration of the freeze period, the commission will revisit the potential conflict between the safety codes for existing security lighting customers.

Economic development and community support:

A number of commenters maintained that regulated utilities should be able to continue to offer, and recover costs through customers' rates for, all economic development and community support activities after September 1, 2000. They argue that economic development is not an "energy" service and, therefore, should not be considered a competitive energy service under the proposed rule.

Other commenters argued that it is inappropriate to permit electric utilities to engage in economic development or community support activities at ratepayers' expense while some other commenters argued that the electric utility should not be able to engage in any economic development or community support activity at all, irrespective of whether the shareholder funds it.

The commission believes that an electric utility may continue to engage in limited economic development and community support activities after September 1, 2000. Economic development and community support activities are not competitive energy services per se. Certain limitations should apply to the provision of these activities by the electric utility after September 1, 2000. The electric utility may not engage in the provision of any competitive energy service under the guise of economic development and community support activities nor may the utility, through economic development and community support activities, promote the provision of competitive energy services or preferentially benefit the utility's affiliate(s).

The commission will thoroughly review the reasonableness of the T&D utility's economic development and community support activities and proposed cost recovery in its review of the April 2000 cost separation filings, but so long as such support is consistent with the above standards and the level of such support is at or below historic levels, the costs should be presumed reasonable.

The commission has taken similar positions on the provision of advertising and customer education activities.

Advanced Metering Services:

In general, the utilities contended that no advanced metering services should be declared competitive energy services, because PURA §39.107 precludes the commission from declaring any type of "metering services" and equipment competitive prior to the dates specified in that section.

Other parties commented that all of the services on the customer side of the meter should be regarded as competitive and advanced metering services and equipment that address or relate to services on the customer side of the basic meter should be regarded as competitive.

The commission believes that the definition of competitive energy service should include a provision for customer-premise metering equipment and related services that are beyond those that are necessary for the measurement of electric energy for purposes of rendering monthly electric bills.

V. On-site generation exemption

Under the statute and the rule, a customer may switch load to on-site generation and avoid stranded cost if the generation meets certain criteria. There are basically three types of generation that qualify: 1) the facility is less than ten megawatts; 2) the unit is a non-qualifying facility (QF) that either was operating or had substantially complete filings at the Texas Natural Resource Conservation Commission (TNRCC) on 12/31/99; or 3) the unit is a QF that had substantially complete filings at the TNRCC on 12/31/99 and was operating and serving load before 9/01/01. However, if the owner of such a facility buys standby service, it will pay a CTC for the standby service. The new on-site generation that is not eligible for the exemption will pay stranded costs based on the CTC for the customer's rate class previous to switching to on-site generation and based on the generation output used for the customer's internal electric requirement.

There are three issues with regard to the way the rule treats this exception to the obligation to pay stranded costs:

(1) How should multiple units of less than ten megawatts be treated?

The rule embraces the proposal put forth by NewEnergy, Texas L.L.C., which was agreed to by a number of parties, including several utilities and Texas Industrial Energy Consumers. This proposal allows the on-site generation owner to designate which units are exempt and which are not.

(2) Can a facility of less than ten megawatts that is exempt from a CTC be added at any time?

The rule permits a person to avoid paying a CTC by switching its load to a facility of less than ten megawatts that is added at any time. The commission believes this is more consistent with legislative intent.

(3) Is the exemption to paying CTC grandfathered to the facility or to the customer?

The rule provides that the exemption is grandfathered to the customer, except for facilities of less than ten megawatts. Because the rule allows facilities of less than ten megawatts to be added at any time, there is no need to limit the applicability of the exemption to the customer for such facilities.

VI. Transmission and distribution utility's contact with retail customers

Some parties contended that all transactions between the T&D utility and an end-use customer should go through the customer's retail electric provider. Other parties have argued that some, even many, transactions can be done without the REP serving as an intermediary. These parties argue that the code of conduct should be sufficient to guard against anti-competitive behavior.

The commission believes, as a general principle, at least for residential customers, the primary and first point of contact for customers should be the customers' REP under all circumstances. The only exception will be emergencies and outages. Having a single point of contact for electric services will cause less customer confusion and less opportunity of abuse by the incumbent utility. The commission expects that the customer call center and billing system for the T&D company will be much smaller than that for the integrated utility that exists today.

VII. Rate of Return for transmission and distribution system

Various investment advisors voiced their concern that the two-percent risk premium is too low. The utilities stated that two-percent is less than their historic risk premiums. Parties on the other side of the issue argue that a two-percent risk premium is too high because the transmission business will be very different from the business of an integrated utility.

The commission continues to recommend the two-percent premium as a default rate of return because it is a reasonable compromise between these points of view. On the one hand, this level of risk premium recognizes the concerns of the utilities because it presents a less formidable barrier to making a showing of special circumstances than a higher risk premium would. On the other hand, a two-percent risk premium is low enough to recognize the significantly lower level of risk that investors might be reasonably expected to have about T&D utilities during 2002. For rates of return on equity that are not based on the two-percent risk premium, the utility must show that there are special circumstances or propose reliability and service quality-based incentive mechanisms that justify the higher return.

Comments

A public hearing on the proposed sections was held at commission offices on October 19, 1999 at 9:30 a.m. Representatives from Reliant, Incorporated (Reliant) and Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities, which are the Texas electric operating companies of Central and Southwest Corporation (collectively CSW) 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 from Abilene Industrial Foundation (ABIF); Alcoa (Alcoa); Alice/ Jim Wells County Economic Development Council (AJWC); Allen Chamber of Commerce (ALCC); Amarillo Area Center for Advanced Learning (AACAL); Angelina Chamber of Commerce (ANCC); Angelton Chamber of Commerce (ANGCC); Aransas Pass Chamber of Commerce (APCC); Area Growth Council (AGC); Arlington Chamber (ARLC); Association for the Advancement of Mexican-Americans (AAMA); Athens Chamber of Commerce (ATHCC); Beaumont Chamber of Commerce (BECC); Bee Development Authority (BDA); Bonham Area Chamber of Commerce (BACC); Bonham Industrial Foundation (BIF); C.L. Sherman; Jr. (CLSJR); Cedar Hill Chamber of Commerce (CHCC); Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities, which are the Texas electric operating companies of Central and Southwest Corporation (collectively CSW); Chambers Elementary School (CHES); Chinese Community Center (CNCC); City Development Corporation of El Campo (CDCEC); City of Clifton Economic Development (CCED); City of Dennison (CDN); City of Friendswood (CFRD); City of Gainesville (CGV); City of Jefferson (CJF); City of Mineral Wells (CMW); City of Nacogdoches (CNCG); City of Shanandoah (CSH); City of Sugar Land (CSL); City of Tolar (CTLR); City of Walnut Springs (CWNS); Clifton Chamber of Commerce (CLCC); Consumers Union; Texas Legal Services Center; and Texas Ratepayers Organization to Save Energy (joint comments) (CU/TLSC/Texas ROSE); Corsican Chamber of Commerce (CCC); Corsicana Industrial Foundation (CIF); Crockett Economic and Industrial Development Corporation (CEIDC); Crowell Industrial Development (CID); Crowell-Three Rivers Chamber of Commerce (CTRCC); Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities (DFWHC/CICU); DECA Texas Association (DECA); Decatur

Chamber of Commerce (DECC); Deer Park Chamber of Commerce (DPCC); Dunagan Warehouse Corporation (DUNWC); East Central High School (ECHS); Economic Development Partnership (EDP); El Paso Electric Company (EPE); El Paso Gas Services Company (EPGS); Enron Corporation (Enron); Entergy Gulf States; Inc. (EGSI); Farmers Branch Chamber of Commerce (FBCC); First Prosperity Bank (FPBNK); Ft. Worth Chamber of Commerce (FWCC); Ft. Worth Hispanic Chamber of Commerce (FWHCC); Galveston County Social Services (GCSS); Galveston Economic Development Partnership (GEDP); Gene Ramsey (GR); Grapevine Chamber of Commerce (GRCC); Greater Corpus Christi Business Alliance (GCCBA); Greater Houston Partnership (GHP); Greater Houston Women's Foundation (GHWF); Greater Irving-Las Colinas Chamber of Commerce (GILCCC); Greater Killeen Chamber of Commerce (GKCC); Hanks High School (HHS); Hopkins Chamber of Commerce (HOPCC); Houston Northwest Chamber of Commerce (HNWCC); J. Tom Melton (JTM); Jackson County Industrial Foundation (JCIF); Jennifer Kolbe (JK); Junior Achievement of Southeast Texas (JASET); Keller Chamber of Commerce (KCC); Kileen Industrial Foundation (KIF); Kilgore Economic Development Corporation (KGEDC); Killeen Economic Development Corporation (KNEDC); Koch Petroleum Group; L.P. (Koch); Lamar County Chamber of Commerce (LCCC); Lavaca-Navidad River Authority (LNRA); League City Chamber of Commerce (LGCCC); Linda Stanhope (LS); Lockhart Chamber of Commerce (LCC); Longview Partnership (LNGP); Lubbock Chamber of Commerce (LBCC); Lubbock Reese Redevelopment Authority (LRRA); Lufkin/Angelina County (LAC); Mansfield Economic Development (MED); Mayor Windy Sitton (MWSTN); McGregor Economic Development Corporation (MEDC); Mesquite Economic Development (MED); Mickey D. West (MDW); Midland Chamber of Commerce (MCC); Mineral Wells Chamber of Commerce (MWCC); Mineral Wells Foundation

(TMWF); Mt Vernon Economic Development Corporation (MVEDC); NAACP (NAACP); Nacogdoches Chamber of Commerce (NACC); Nacogdoches County Chamber of Commerce (NCCC); Nacogdoches Economic Development (NED); Nancy L. Smith (NLS); National Association of Energy Service Companies (NAESCO); Nederland Economic Development Corporation (NDEDC); Neighborhood Centers Incorporated (NCI); Neighborhood Recovery and Community Development Corporation (NRCDC); NewEnergy, Texas L.L.C. (NewEnergy); Noel Investments (NI); Nucor Steel (Nucor); Occidental Chemical Corporation (OxyChem); Odessa Chamber of Commerce (OCC); Odessa Chamber of Commerce (ODCC); Office of Public Utility Counsel (OPC); Pearland/ Hobby Area Chamber of Commerce (PHCC); PG&E Corporation (PG&E); Professional Insurance Agents (PIA); Reliant; Incorporated (Reliant); Representative David Lengefeld (RDLD); Representative Edmund Kuempel (REKL); Representative James L Keffer (RJLK); Representative Jim Pitts (RJP); Representative John E Davis (RJED); Representative Leo Berman (RLB); Representative Pete Gallego (RPGO); Representative Arlene Wohlgemuth (RAW); Representative Gene Seaman (RGS); Representative Vicki Truitt (RVT); Richardson Chamber of Commerce (RDCC); Richey Company (TRC); Roanoke Trophy Club Westlake (RTCW); Round Rock Chamber of Commerce (RRCC); S. Montgomery County and The Woodlands Chamber of Commerce (SMCWCC); San Angelo Economic Development (SAED); San Antonio Chamber of Commerce (SACC); San Antonio Economic Development (SATED); San Antonio Economic Development Foundation (SAEDF); San Patricio County (SPC); Sealy Economic Development Corporation (SEDC); Sen. J.E. Brown (SJEB); Shell Services Company; L.L.C. (Shell); Sherman Chamber of Commerce (SHCC); Sherman City Council (SHCCL); Sherman Economic Development (SHED); Silsbee Chamber of Commerce (SCC); Sonat Power Systems; Inc. (Sonat); Sour Lake

Chamber of Commerce (SLCC); Southlake Chamber of Commerce (SOLCC); Southwestern Public Service Company (SPS); Spring Branch Independent School District (SBISD); State of Texas; by the Office of the Attorney General (OAG); Steering Committee of Cities Served by Central Power and Light Company; and Steering Committee of Cities Served by TXU Company (joint comments) (Cities); Sweeney Chamber of Commerce (SCC); Taylor Chamber of Commerce (TACC); Taylor Economic Development (TED); Teague Chamber of Commerce (TECC); Temple Chamber of Commerce (TMPLCC); Temple Economic Development Corporation (TEDC); Texas Air Conditioning Contractors Association; and Independent Electrical Contractors Associations of Texas (joint comments) (TESCO/TACCA/IEC); Texas Apartment Association (TAA); Texas Association of Business and Chambers of Commerce (TABCC); Texas Building Owners and Managers Association (Texas BOMA); Texas Community Associations Institute (Texas CAI); Texas Economic Development Council (TXEDC); Texas Energy Service Coalition (TESC); Texas Independent Energy, LP (TIE); Texas Industrial Energy Consumers (TIEC); Texas Industries; Inc. (TXI); Texas Municipal League (TML); Texas-New Mexico Power Company (TNMP); Texas Retailers Association; Texas Restaurant Association; Texas Petroleum Marketers & Convenience Store Association; Texas Apartment Association; Texas Building Owners & Managers Association; Independent Bankers Association of Texas; and Texas Hotel/Motel Association (joint comments) (Commercial Associations); Three Rivers Chamber of Commerce (TRCC); Tracy Brazile (TB); TXU Electric Company (TXU); Tyler Economic Development (TED); Victoria Economic Development Corporation (VEDC); Wheeler Avenue Baptist Church (WABC); White Settlement Area Chamber of Commerce (WSACC); Wichita Falls Board of Commerce (WFBC); Wichita Falls Chamber of Commerce (WFCC); and Women Helping Women (WHW).

In the preamble to the proposed rule the commission posed the following questions:

First question:

Does the provision in PURA §39.253 that stranded costs be allocated in accordance with the methodology used to allocate the costs of the underlying assets in the utility's most recent commission order addressing rate design require that the specific numeric (production demand) allocators or the methodology for the (production demand) allocator for the purposes of allocating ECOM among customer classes?

The allocation approaches advocated by different parties can be grouped into four broad categories. There may be variations within each group.

(1) *Numeric or Intent approach.* The commission should use specific numeric production demand allocators from the last rate case and weather-adjusted energy allocators from the test year ending May 1, 1999. No known and measurable adjustments to demand or energy allocators should be permitted *except* for (1) those rate classes which were not identified as a separate class in last cost of service study and (2) for imputed revenues. Billing determinants should be based on a forecasted 2002 test year. (Advocates: OPC, Shell, CU/TLSC/Texas ROSE, OAG, Commercial Associations, DFWHC/CICU and Cities)

(2) *Methodology approach.* The commission should use production demand allocators (using the allocation methodology from the last rate case) and weather adjusted energy allocators from test year ending May 1, 1999. Known and measurable adjustments to *both* demand and energy allocators should be permitted to reflect a forecasted rate year 2002. Billing determinants should be based on the same test year or a forecasted 2002 test year. (Advocates: TNMP, Reliant, EGSI, Nucor, TIEC, TXI and TIE)

(3) *Adjusted numeric approach.* The commission should use specific numeric production demand allocators from the last rate case and weather adjusted energy allocators from the test year ending May 1, 1999. Known and measurable adjustments for material changes to demand *and* energy allocators should be permitted, including customers switching to eligible on-site generation for a rate year 2002. Billing determinants should be based on a forecasted 2002 test year. (CSW)

(4) *Case-by-case approach.* Any variation of one of the above approaches, depending on the utility. (TXU, CSW)

Koch stated that it supports the comments made by TIEC with regard to allocation of stranded costs.

Statutory language & statutory intent

OPC, Shell, CU/TLSC/Texas ROSE, OAG, Commercials Associations and Cities commented that the term *"methodology used"* includes allocation procedure (for example, A&E-4CP) *and* the actual numbers resulting from applying that methodology to the test year data. According to these parties, it is consistent with the language in PURA §39.253 and the legislative intent to use the specific numeric production demand allocators from the last rate case.

Cities stated that the precise articulation of percentage allocators itself *is* a methodology, and the statutory reference means that the demand portion of stranded costs should be allocated in a manner consistent with specific numeric allocators previously found reasonable by the commission. According to Cities, the Legislature was not concerned whether some form of coincident peak or average and excess approach had been used to allocate costs. Rather the Legislature's concern was that the percentage of demand costs allocated to customer classes not change as result of SB7. TXI objected to Cities' comments that the precise articulation of allocation percentage is a methodology. TXI stated that the language of SB7 is clear and unambiguous in its reference to methodology rather than allocators.

Enron disagreed with certain parties' claims that the fundamental issue concerning the allocation of stranded costs is one of interpretation of legislative intent. Enron stated that the elimination of the CTC in the shortest amount of time would benefit *all* customers, both large and small. Enron also disagreed with the comments that any class or customer will be harmed if *current* class characteristics instead of historical are utilized, and added that the commission should not allow any cost recovery or rate design that varies from traditional cost causation and accepted ratemaking principles. Enron also stated that if the intent of SB7 is to allow *all* customers to reap the benefits of competition, the commission must consider the *overall* intent of the legislation and formulate the rules accordingly.

TXU stated that the phrase "methodology used" could mean either the procedure used to calculate the production demand allocators from the last rate case or the specific numeric production demand allocators themselves. Therefore, the use of either would comply with the statute.

CSW, TNMP, Reliant, EGSI, Nucor, TIEC, TXI and TIE stated that the law explicitly says "methodology" with no reference to historical numeric allocators. According to these parties, it is consistent with the language of the statute and long-standing ratemaking principles to use current usage characteristics. TXI stated that methodology, and not numeric production demand allocators, must be used as a matter of law, good policy, and fundamental fairness. According to TXI, one must look to the express language of the statute and despite the belief by some parties that they know the exact intent of the Legislators who wrote SB7, the *entire* legislative body voted on the language in the bill. CSW noted that CPL's last rate case had a test year ending June 30, 1995 and the use of factors from such an old test year could jeopardize the utility's ability to recover its stranded costs or cause disproportionate costs to customers within a class. According to CSW, at the least, a utility should be allowed to make adjustments for material known and measurable changes to the historical numeric production demand allocators and to the energy allocator from test year May 1, 1999.

Enron stated that it opposes any method of stranded cost allocation that results in certain classes paying more or less than their fair share. According to Enron, although the legislation clearly attempts to derive a relationship between historical rate design and the historical nature of stranded costs, it does not believe that the legislation was intended to ignore changes in customer usage and customer classification over time.

Shell, OPC, Commercial Associations and OAG replied to the comments that the plain language in PURA §39.253 refers strictly to "methodology" and not numeric production demand allocation factors from the last order. According to these parties, the statutory language refers to "methodology used to allocate", and methodology alone does not allocate. Commission rate case proceedings determine the method to allocate *and* the resulting production allocation factors. These parties noted that nothing could be in greater accord with the description "methodology used" than the specific numeric allocators did.

Agreement among the stakeholders during the legislative session

Commercial Associations stated that it was essential for them to be able to quantify, to the extent possible, the shift in stranded cost responsibility from residential customers to commercial and industrial customers based on the compromise reflected in Floor Amendment Number 26. According to the Commercial Associations, the negotiators dealt with actual demand allocation factors from the last general rate case in coming to a compromise on PURA §39.253, in order not to leave the factors open to dispute in some future rate proceeding. TXI disagreed with Commercial Associations' argument, and stated that the disparity between the allocated amounts using the historic numeric allocators Commercial Associations agreed upon and updated allocators does not justify reliance upon legislative history. According to TXI and TIEC, the schedules Commercial Associations relied upon when making their decisions during the legislative session are not part of the legislative record, and therefore cannot be used to prove that the statute should be read in a manner inconsistent with its express language. According to TXI, had the Legislature intended that the specific numeric allocators are to be used instead of the underlying methodology, it could easily have modified the statutory language to that effect.

TIEC commented that in determining the legislative intent, the commission should look first to the language of the statute but only if the language is ambiguous to the legislative record. To the extent that the agreements between parties are relevant to the legislative history, they may be considered only if they are part of the legislative record. TIEC added that for §39.253, it is only the language in this section that was agreed upon, and the language is the only evidence of the agreement in the legislative record. In reply comments, Commercial Associations stated that TIEC is attempting to walk away from the deal. According to Commercial Associations, that deal substantially reduced the impact on industrial customers of Committee Amendment Number 59, which contained use of energy allocators to allocate all of the stranded costs.

September 22, 1999 Letter from Representatives Wolens, Brimer, and Bailey to Chairman Wood

In support of their positions, several parties including CU/TLSC/Texas ROSE submitted or referred to a letter from Representatives Wolens, Brimer, and Bailey to Chairman Wood concerning the allocation of stranded costs.

Shell stated that updating the allocation percentages to reflect more recent consumption data would violate the Legislature's intent. According to Shell, the Legislature did not intend that the commission should update the demand allocators and the letter is supportive of that.

DFWHC/CICU and OAG also stated that the letter resolves the debate.

Commercial Associations stated that the letter is consistent with the common sense interpretation of the term "methodology used". According to Commercial Associations, the letter should be accorded great weight because these are the legislators who helped to facilitate the agreement which resulted in House Floor Amendment Number 26, by Bailey.

TXI responded to the parties who referred to the letter arguing that even if it were appropriate to resort to such "extrinsic evidence" of legislative intent, the letter is not part of legislative record and therefore not part of the legislative history. TIEC stated that it is not advocating that the allocators be set sometime in the future, which appeared to be the chief concern the Legislators expressed in the letter. TIEC noted during the recent negotiations facilitated by commission staff, it has proposed that the allocators and billing determinants be based on consistent data, which means that a historical test year such as 1999 could be used for both. According to TIEC, this would more accurately reflect the composition of the classes as they existed when SB7 was passed.

Avoidance of litigation

OPC and CU/TLSC/Texas ROSE asserted that one of the chief concerns of the Legislature was potential litigation over stranded cost allocation. This concern is reflected in the provision §39.253(g) specifically directing the commission to use energy allocators as of May 1, 1999.

OPC argued that because the phrase "in accordance with the methodology used to allocate costs of the underlying assets" only generally states the Legislature's intent, the commission should look to the legislative purposes of this phrase. According to OPC and CU/TLSC/Texas ROSE, it would have been inconsistent on the part of the Legislature to attempt to minimize litigation over the energy allocators and then to ignore the same potential for litigation over demand allocators.

Shell stated that updating the allocators would unnecessarily prolong the cost separation proceedings (as described in proposed §25.344) and require significant resources from the commission and the parties to analyze the data.

TXI and TIEC replied to CU/TLSC/Texas ROSE's and OPC's argument that one goal of SB7 was to avoid litigation and that the use of numeric allocators would accomplish that goal. TXI and TIEC stated that, historically, the "big battles" in rate proceedings focused upon the appropriate allocation methodology or formula, such as whether to use capital substitution methodology in lieu of an Average and Excess Coincident Peak methodology or whether production plant should be allocated based on demand or energy. According to TXI, if the Legislature's intention were to minimize further litigation, then this goal would be achieved whether the historical numeric allocators or updated data using the same methodology is used.

TIEC and EGSI agreed, adding that once the allocation methodology, is chosen, it is a fairly straightforward matter to determine the specific numeric allocators. TIEC also added that this provision of SB7 evolved from requiring a demand based allocation methodology, to a pure energy allocator, and the final compromise was to use demand and energy each at 50%, to prevent litigation on whether to use demand or energy allocators. TIEC also disagreed with OPC, stating that if the primary goal of PURA §39.253 was to prevent litigation by using only historical allocators, the Legislature would not have separately specified the energy allocators in §39.253(g) since both demand and energy allocators were set in the last order addressing rate design. TIEC further commented that parties concerned with minimizing litigation are also suggesting adjustment to historical demand allocators for special rate classes and imputation. According to TIEC, these parties' proposal contradicts their position to use historical allocators.

Ratemaking principles

Enron stated that under fundamental ratemaking principles, the allocation of stranded costs should reflect customer load characteristics as they exist during the time the Competition Transition Charges (CTC) will be in effect. Nucor and TIEC stated that the fundamental ratemaking principles require (1) using the most up-to-date data that is representative of the period that rates are to be in effect, and (2) matching billing determinants by using all data from the same period. TIEC stated that ratemaking is neither now, nor has it ever been, a *static* process and nothing in SB7 requires a fundamental change in the dynamics of the ratemaking process. TIEC stated that cost of service studies for many utilities are outdated and ignoring the recent dramatic changes in the consumption pattern would result in the improper cross-subsidization of some classes by others.

Nucor recommended that since the statute prescribes a May 1, 1999 test year for energy usage data, appropriate matching principles require that May 1, 1999 test year data be used to determine all allocation factors and billing determinants to calculate all CTCs. Cities objected to Nucor's suggestion to use the May 1, 1999 test year for allocation factors and billing determinants instead of 2002 billing determinants. According to Cities, this would create a dramatic mismatch between billing determinants and revenue requirements.

OPC stated that the commission should remember that the stranded costs are historic costs of utilities; therefore, the rate classes as historically constituted should bear their share of stranded cost recovery. OPC also noted that, in some instances, the historic allocators must be recalculated to reflect the implicit stranded cost assignments to special rate riders and classes which were not directly allocated costs within the cost of service study. According to OPC, this is necessary for two reasons: (1) to carry out the mandate that non-firm customers pay 150% of stranded costs embedded in their rates; and (2) to reflect the total allocation of stranded cost among all classes resulting from a prior rate case. OPC also stated that the commission should recognize that for some utilities the historic demand allocators should be adjusted to reflect inclusion of imputed revenues and capacity-related purchased power cost recovery factor (PCRF) revenues in the base revenues of the utility.

OAG stated that it recognizes that updating the factors to reflect the current conditions would be in keeping with fundamental ratemaking principles. However, according to OAG, in this instance more recent data is not necessarily better data from an equity standpoint. OAG also added that what is being allocated is not overall revenue requirements, but rather a small subset thereof which is related to investments made many years ago.

In reply comments, DFWHC/CICU stated that in many of the proceedings addressing rate design many issues were resolved by settlements that did not disclose the basis upon which agreement was reached. According to DFWHC/CICU, parties supporting the "methodology" option are ignoring this reality and presuming that the Legislature believed that every settlement could be clinically dissected to individually identify a method underlying the design of rates. DFWHC/CICU noted that what could be established with assurance is the proportionate allocation that resulted under the settlement.

In response to the claim that some cost of service studies are outdated, DFWHC/CICU, OPC and Shell stated that stranded costs are *historical* costs; and therefore, it is incorrect to compare the stranded cost allocation with traditional ratemaking. According to these parties, a focus exclusively on future circumstances ignores the critical dimension of the stranded costs, as well as the reason utilities maintain that costs indeed are "stranded" and require a special recovery mechanism. OPC noted that traditional ratemaking involves a determination of a utility's revenue requirement that is most likely to occur on a *forward-looking* basis while the rates to be set will be in effect. In clear contrast, stranded costs are historical sunk costs of electric utilities related to power generation. Therefore, the responsibility of a class for recovery of historical stranded costs is not related to the class' *future* use of generation.

In reply comments, Commercial Associations argued that traditional ratemaking would not mandate that 50% of purely *demand*-related capacity costs be allocated based on *energy* usage as set forth in PURA §39.253, and that the Legislature is not limited to traditional ratemaking approaches.

Migration of customers

TIEC stated that allocating stranded costs among rate classes based on historic data and then recovering these costs from the classes using 2002 billing determinants would mismatch allocated costs and cost responsibility. In some instances, such a mismatch could create tremendous problems for certain classes of customers. TIEC noted that customers have migrated over time either to different rates or off the system to pursue self-generation options. In addition, some customers will be able to avoid the CTC if they are qualified as eligible on-site generation as in proposed §25.345(c)(2). According to TIEC, the potential adverse impact on remaining customers is not trivial and the increase in CTCs for these customers has nothing to do with cost causation. The remaining customers would have to pay substantially higher CTCs as a consequence of actions over which they had no control.

TXI stated that old allocation factors reflect obsolete cost and load relationships and, given the vast amount of stranded costs, the "harm" or "windfall" to customer classes can be substantial.

EGSI stated that it has had several rate changes since the test year used in Docket Number 16705, *Application of Entergy Texas for Approval of its Transition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and To Recover a Surcharge for Under-Recovered Fuel Costs*, which have resulted in customer migrations from one class to another. EGSI also added that it has had a significant number of customers switch from the interruptible class to a firm class. Using the specific historical allocators from Docket Number 16705 and fixing the dollar amounts would result in allocating costs related to *fifteen* customers among the current *eight* customers. EGSI recommended that the methodology should be applied to the test year ending May 1, 1999, adjusted for known and measurable changes for customers who will be switching to eligible on-site generation. This would allow for logical alignment of the demand allocation with the energy allocators test year mandated by PURA §39.253.

According to Shell, the "one customer remaining in a class" phenomenon that TIEC and others contemplate likely will not occur. Shell further noted that those customers left behind would be the most highly sought-after customers in the restructured market. Shell also stated that the commission could assign a specific CTC that would follow these customers (a process referred to as "tagging"), which would prevent shifting of those customers' stranded costs to the remaining customers.

In its reply comments, Commercial Associations stated that the letter from the State Representatives indicated that the consequences of migration was not discussed during the legislative session, but the legislators left no doubt that the effects of the loss of customers within a class was the responsibility of that class.

In response to those commenting that it would be unfair to the remaining industrial customers to pay for the stranded costs of the customers who migrate to another class or start self-generation, OPC stated that it would be an injustice to shift part of those costs to the residential and/or commercial customers. OPC added that PURA provides remedies for potential collection problems (e.g., §39.262 and §39.307). Furthermore, the commission should not penalize residential and commercial customers by preemptively shifting costs solely on the basis of a perceived potential collection problem. OPC also stated that industrial customers consistently resist reasonable measures such as consolidation, and if any adjustment is to be made, it should be done within that class.

Securitization

CU/TLSC/Texas ROSE noted that securitization transition charges must also be allocated as prescribed in §39.253, and that the commission must issue a financing order in those proceedings within 90 days. It would be impossible to complete a securitization proceeding within 90 days if the commission and parties had to re-litigate demand allocation factors based upon a general methodology but subject to various interpretations, adjustments, and manipulations. TXI replied that there is no reason to believe that any significant issue other than, perhaps, weather or year-end customer growth would arise. According to TXI, application of the methodology is a purely mechanical process. TXI also asserted that there is no reason why the financing order must specify the allocation of the transition charges, other than to require that they be allocated in the same manner as the CTCs.

TIEC stated that the benefits of securitization are based entirely on the ability of utilities to receive a AAA bond rating. If there is a realistic possibility that some class of customers will not exist, utilities will not receive their desired rating. Shell disagreed with the argument that a historic numeric allocator somehow will jeopardize securitization efforts and stated that such arguments are merely speculation, which relies upon the occurrence of several unlikely events. OPC also objected to TIEC's claim that using the numeric allocators would have negative public policy consequences by stating that PURA provides for mechanisms to address potential under-recovery issues (e.g., §39.262 and §39.307). According to OPC, if the commission implements these mechanisms, the revenue stream will be secure and bonds would receive the AAA rating.

Benefits of competition for residential class

OPC stated that another concern of the Legislature was the development of future retail competition for residential customers. According to OPC, on numerous occasions legislators expressed concern that the retail margin between the incumbent's price to beat and the non-bypassable charges would be too thin to allow development of effective competition. Interpreting the statute to mean only the *methodology* from the last rate case and not the *numeric demand allocators* from the last rate case would partially offset the reduction in the residential CTC that the Legislature created by fixing the allocators to a certain date. OPC added that the differences in production allocation between the historical numeric factors and the more recent ones might appear to be small percentage-wise. However, that appearance is misleading, because it fails to consider the impact on margins that are available to REPs who desire to serve residential customers.

CU/TLSC/Texas ROSE and Shell stated that resolution of this issue is critical to the success or failure of the retail market for residential customers. According to these parties, updating the factors to 1999 or 2002 load data would shift more costs to the residential class, because this class has the highest load growth. This will reduce the "shopping credit" even further, making it less attractive for a retail electric provider (REP) to enter this market. In reply comments, Shell added that the resolution of stranded cost allocation represents perhaps the most important factor in determining whether a REP will enter the residential market. According to Shell, new REPs would be competing against a 6.0% rate reduction and an incumbent affiliated REP with a strong connection to the transmission and distribution utility (T&D utility). Shell stated that these factors leave very little margin for non-affiliate REPs to enter the residential market.

TXI replied to CU/TLSC/Texas ROSE and Shell's comments regarding the reduction in shopping credit. TXI stated that shifting stranded cost to non-residential classes would affect the profit margins of the REPs serving these customers, or, alternatively, the profitability of these customers. According to TXI, the profitability of end-use industrial customers is in fact significant to the economic health of this state and ultimately to the economic well being of the residential customers of Texas. TXI also stated that because of the fast load growth in the residential class, even though more stranded cost dollars might be shifted to that *class* overall, each *customer* in the class will not be harmed. TXI added that insuring the viability of residential competition is a worthy goal, but should not take precedence over issues of fundamental fairness.

TIEC also replied to the comments made by OPC, Shell and CU/TLSC/Texas ROSE regarding the reduction in shopping credit. TIEC stated that what happened in California and Massachusetts (i.e. no retail competition for residential class) did not have anything to do with allocation of stranded costs in those states but rather related to other factors. TIEC also objected to OPC's claim that updating the demand allocators and billing determinant data would partially offset the reduction in the residential CTC the Legislature created by using the historic demand allocators. According to TIEC, this is hardly the case, since half of the costs would be allocated based on energy instead of demand allocators that historically have been used.

OPC responded to TIEC by stating that the primary concern regarding the shrinking of shopping credits (the "head room issue") is whether a significant number of new non-incumbent REPs will be economically capable of serving all segments of the retail market, particularly residential and small commercial customers. According to OPC, if the affiliated REP continues to dominate the market for these customers because entry is difficult, residential and small commercial customers will face a deregulated monopoly rather than a competitive market. OPC added that the concept of "headroom" requires an implicit price ceiling such as price to beat, which is only applicable to residential and small customers. OPC also added that a larger industrial CTC will increase the industrial customer's bill, but it will not foreclose or inhibit the ability of non-incumbent REPs to compete for that load. OPC stated that the headroom issue is a very important policy consideration in interpreting the term "methodology". According to OPC, the sizable amounts of revenue per customer reduce transaction costs for industrial customers, and permit REPs to compete purely on power acquisition costs. In contrast, the much smaller revenue per customer associated with residential users increases transaction costs for REPs and requires them to expend considerable sums on marketing and advertising. Therefore, increases in the CTC allocation to the residential class which appear to be relatively small, in fact may have a substantial adverse impact upon the ability of competitors to enter the market.

Energy allocator

Cities and OPC stated that TIEC, EGSI and CSW, in addition to updating the production demand allocators, incorrectly suggested making adjustments to the energy allocator for known and measurable changes. According to Cities and OPC, SB7 is explicit in pegging the energy allocator at a certain date (May 1, 1999), and the only adjustments allowed are for weather normalization.

Case by case approach

TXU stated that the commission should consider writing proposed §25.345 in a manner that does not require use of either the "methodology" or the numeric allocators to the exclusion of the other. According to TXU, it may be appropriate to use one or the other for each utility, in accordance with each utility's particular situation or the specific provisions of the controlling historic order. Cities and OPC urged the commission to make a policy determination on the calculation of the demand component of stranded cost allocation in accordance with PURA §39.253 as a part of its adoption of these rules.

Koch stated that if the commission decides to use data for allocators and billing determinants from two different time periods, the methodology should be developed and reviewed on a company by company basis in the rulemaking process. Koch added that if such an evaluation cannot be accomplished during the rulemaking process, it could be taken up in the securitization or cost separation proceedings.

CSW also stated that each utility is unique and the allocation and recovery of stranded costs should be determined on a utility-by-utility basis. CSW added that if known and measurable adjustments are not made to historical demand allocators and May 1, 1999 energy allocators, an inequitable allocation will result, an outcome which would be time-consuming to correct through the true up. CSW stated that it estimated that approximately 50% of CPL's interruptible customer's load and 20% of CPL's firm load would leave the CPL system to eligible on-site generation, thereby avoiding the CTC.

Best practices from other states

TIEC responded to the commission's request in the preamble examples of best practices in other states. According to TIEC, none of the states that have implemented customer choice has fixed the dollar amounts of stranded costs to customer classes based on historic data, as the numeric approach requires. All states are collecting stranded costs based on future usage of the classes.

OPC and Commercial Associations disagreed with TIEC's suggestion, noting that many provisions of SB7 are unique to Texas. DFWHC/CICU also responded to TIEC and noted that the assertions are made without reference to any cited statutory language. According to DFWHC/CICU, Pennsylvania law flatly provides that costs to be recovered shall be allocated to the customer in a manner that does not shift inter-class costs. (Electricity Generation Customer Choice and Competition Act, Section 2808(A)) DFWHC/CICU also stated that Illinois' statute mandates that "each electric utility shall file tariffs that establish transition charges to be paid by each class of customers." (Electric Service Customer Choice and Rate Relief Law of 1997, Section 16-108(g)).

The commission concludes that the cost allocation issues regarding the development of the demand allocators used to determine the Texas retail allocation should be addressed on a case by case basis in either the utilities' securitization cases or their April 2000 cases. These allocation issues are policy related, but it is desirable to tailor the allocators to fit the different situation each utility is in. The particular circumstances of each utility should be examined and used to determine the appropriate allocation methodology for the utility. Because the statute allows for an earlier timeline for the application of securitization than that for the April 2000 cases, and three utilities are currently seeking securitization before the commission, the commission believes that the record developed in the securitization cases should be used to determine the allocation methodology for each of the utilities seeking securitization of regulatory assets. As for utilities not seeking securitization before the April 2000 cases, the factual record needs to be developed in the April 2000 cases before these allocation issues can be properly addressed. However, the commission's decisions regarding these allocation issues in the three pending securitization cases will give guidance as to the general direction for allocation for other utilities seeking recovery of stranded costs.

The commission also concludes that the energy allocator used in the allocation of Texas retail stranded costs should be determined based on the energy consumption for the test year ending May 1, 1999, adjusted only for weather, as prescribed clearly in PURA §39.253(g).

In addition, the commission concludes that the allocation to special rate classes which do not have an allocator in the utility's last cost of service study should be determined based on their generation-related revenue embedded in their total base rate revenue requirement from the utility's last rate case. For the rate classes that have been determined as discounted rate schedules by the commission, the revenue used to determine the allocation for them should include the imputed revenues.

Second question:

Is the allocation of stranded costs to classes pursuant to PURA §39.252 meant to fix each class's share of ECOM, or is the allocation meant to be used to design a fixed competition transition charge (CTC) for each class? In other words, as any given customer class experiences load growth, should the benefits of that growth be retained within the class in the form of a declining CTC or more rapid collection, or should those benefits be spread over the entire system?

Generally, the parties who supported the *numeric approach* in response to Question Number 1 also supported the fixing of stranded costs dollar amounts once the initial allocation is done, consequently keeping the benefit of the load growth within the class. TXU also favored this position. (*Class by class reconciliation approach*) However, there was disagreement among these parties as to whether the CTCs set in either the cost separation proceedings or the securitization proceedings should also stay fixed until the true-up.

CSW, as well as the parties who supported using the *methodology approach* in response to Question 1, supported not fixing the dollar amounts and spreading the benefits of the load growth over the entire system *(System wide reconciliation approach)*.

Cities, Commercial Associations, CU/TLSC/Texas ROSE, OAG, OPC, Shell and TXU stated that the statute requires fixing each class' share of ECOM dollars after the initial allocation and retaining the benefits of load growth within the class. CU/TLSC/Texas ROSE, OPC and Shell referred to PURA §39.253(i), and stated that this section prohibits "any customer *or customer class*" (emphasis added) from avoiding the obligation to pay the amount of stranded cost allocated to that customer class. OPC and Cities recommended fixing the CTCs until the true-up period. Shell, CU/TLSC/Texas ROSE and OAG stated that CTCs should be adjusted annually pursuant to PURA §39.201(g) in order to reflect changes in a utility's ECOM levels as reflected in its annual report.

OPC stated that SB7 does not mandate continuous adjustments in the CTC billing determinants to account for load growth. According to OPC, at the time of true-up proceedings, the over/under-recovery would be reconciled by class. The CTC or the amortization period could then be adjusted in accordance with the initial allocation to reduce the impact on the customers in a shrinking class.

TXI and TIEC objected to OPC's, CU/TLSC/Texas ROSE's, and Shell's interpretation of PURA §39.253(i). According to TXI, such a reading is strict, narrow, and inconsistent with the overall purpose and intent of SB7. TXI stated that the more logical interpretation of PURA §39.253(i) is that it is a statement of principle, which is not intended to preclude the commission from addressing load growth and load loss issues. TIEC argued that cost causation looks at how *a customer* uses electricity and the impact a *customer* has on the costs of a utility. According to TIEC, by confining load growth to each customer class, the CTCs in that class will change, (since the fixed amount of stranded costs will be divided to larger billing determinants because of the new customers using the system) even if the usage of each individual customer does not change. Enron stated that a customer that improves its use of a utility's electrical system through investment in energy efficiency equipment and/or improved production processes should not be required to pay an increased CTC as the respective customer class load and/or class demand shrinks.

Commercial Associations stated that by agreeing to the use of a partial energy allocator instead of pure demand, their clients agreed to assume a greater burden of stranded cost. This is because unlike the demand allocator, the energy allocator shifts more costs to high load factor customers, who are among the clients of Commercial Associations. According to Commercial Associations, it would be unfair to add to this burden by shifting more costs as a result of the loss in industrial load, especially in CPL's system. TXI strongly disagreed with Commercial Associations' notion that it would be *unfair* to spread the burden of lost load within a class across the entire system. TXI argued that load growth or loss within a class are uncontrollable by individual class members, and surpluses and shortfalls have been spread across the system in every rate proceeding undertaken since the inception of the commission.

CSW, Enron, EGSI, Nucor, Reliant, TIEC and TXI stated that PURA §39.253 was not meant to fix each class' share of ECOM dollars, *regardless* of the change in load characteristics of the class over the years. According to these parties, to keep the benefits of load growth within the same class would be contrary to the fundamental rate setting principles applied in Texas. These commenters recommended the spread of the benefits from load growth over the entire system, just as has always been done. TIEC also noted that customer classes were created as a convenience to set rates, and that the cost of serving a customer does not change just because the class of customers may be growing or shrinking. Reliant argued that rates determined in a rate case proceeding are, in reality, charges to an *individual customer* and not total costs to *classes*. Therefore, it is not reasonable to assume that an *individual customer* is responsible for all the costs of a class, merely because it happens to share characteristics with other customers in that class.

EGSI stated that it is necessary to set a fixed CTC for each class in order to comply with PURA §39.201. EGSI also noted that total jurisdictional recovery should be periodically reviewed and all classes should share equally in the changes in the total jurisdictional recovery.

OPC and Shell responded to the argument that retaining the benefit of load growth within a class is against traditional rate setting principles. OPC and Shell noted that stranded costs are *historical sunk costs,* which will never change in response to changes in future demand. According to Shell, customers should pay stranded costs in proportion to their responsibility for creating those stranded costs, not in proportion to their responsibility for creating new, non-stranded costs. According to OPC, given the framework of SB7--a legally binding allocation of stranded costs to customer classes and a reconcilable stranded cost balance--the most logical resolution of the issue is:

(1) to maintain records of over/under-recovery by customer class;

(2) to apply a fixed CTC between 2002 and 2004; and

(3) to use several tools provided by PURA (*e.g.*, in §39.262 and §39.307) in true-up proceedings to mitigate any anomalous results within a class.

OPC recommended that if the transition cost factor for securitized assets has been subjected to annual true-ups, any net cumulative over/under-recoveries of those assets within each customer class should also be taken into account in readjusting CTC factors and transmission and distribution rates during the 2004 true-up proceedings. Shell also stated that SB7 contains no provision that allows the commission to reallocate stranded costs, once allocated in the cost separation proceedings. Shell noted that if indeed the Legislature intended current cost causation proportions to govern, it would have required the commission to use a pro forma 2002 test year for stranded cost recovery, as it did for transmission and distribution rates (PURA §39.201(b)(1)).

Commercial Associations also responded to TIEC's comments, stating that, in requiring the non-firm class to be responsible for 150% of the historical allocation factor, the Legislature was beginning to address the failure by non-firm customers to pay their share of the fixed costs of nuclear generating facilities. These plants were built to serve the entire existing and forecasted industrial load, but non-firm customers avoided paying their fair share through discounted rates. Commercial Associations argued that non-firm load would still be paying a much lower CTC than the firm load if the historical allocators are used, since it is based on discounted demand allocators to begin with.

DFWHC/CICU also responded to TIEC, TXI and Nucor by stating that industrial customers have captured the most favorable rates from utilities and received incentives to increase electricity consumption, thereby requiring more capacity to be built. According to DFWHC/CICU, while TIEC, TXI and Nucor admit that fundamental principles of rate making require rates to be based on *cost causation*, they also object to the recovery of stranded costs from the industrial customers who *have caused* part of historical stranded costs. DFWHC/CICU also objected to TIEC's claim that remaining customers would have to pay the CTC as a result of actions over which they have no control. DFWHC/CICU noted that residential and commercial customers have even less to do with the actions of industrial customers. DFWHC/CICU also stated that to use benefits of load growth in non-residential classes penalizes, and provides a disincentive for, the future load growth. According to DFWHC/CICU, load growth on a prospective basis increases demand, all else being equal, and increases the market price of electricity. The higher the electricity prices, the lower the ECOM. DFWHC/CICU argued that, not only would residential and commercial customers provide the demand impetus for higher prices and lower stranded costs overall, but they would be asked to take up the slack for shortfalls in industrial demands.

As with the allocation issues discussed in the first preamble question, the commission determines that the issue related to whether the initial allocation to the classes should stay fixed or not should be addressed on a case by case basis in either the utilities' securitization cases or the April 2000 cases. The commission finds that it is premature to make decisions based on hypothetical load loss or growth scenarios in this rulemaking. The parties and the commission will review the forecasted load data for 2002 and beyond at the time of the securitization filings or the April 2000 unbundling filings. In addition, customer characteristics and growth rates for each class, as well as the amount of the stranded costs, are unique to each utility. Therefore the commission does not find it necessary to specify a reconciliation approach (system-wide or by class) applicable to all utilities in this rulemaking.

The commission disagrees with EGSI on the subject of the periodic update of the jurisdictional allocation factor. However, based on the same reasons that it handles other major cost allocation issues, the commission concludes that the cost allocation issues regarding the jurisdictional allocation should be addressed on a case by case basis in either the utilities' securitization cases or their April 2000 cases.

Third question:

If the allocation of stranded costs is fixed to one or more classes, what is the best method to account for potential migration of commercial, industrial, and non-firm customers between classes, to on-site generation, or out of the utility's service territory? For example, if migration concerns can be mitigated through the consolidation of some classes, how should existing classes be combined for the purposes of stranded cost collection? Should customers who remain in classes that experience large amounts of out-migration be protected from having to bear increasing responsibility for that class's stranded costs?

In general, utilities supported the class consolidation to mitigate concerns related to customer migration, whereas non-utilities stated other concerns. TXU, CSW, EGSI and Reliant agreed that class consolidation when applied *together* with system wide true-up rather than true-up per class would mitigate the migration concerns. TXU noted that the commission should only consolidate classes on the basis of common customer characteristics.

Nucor, TXI and TXU recommended tagging as a means to address the migration problem. Cities stated that impact of migration on remaining customers should be addressed in the true up proceedings. Cities and EGSI stated that a generic rate class consolidation should not be mandated to all utilities in the rule and the issue should be decided on a utility by utility basis.

Commercial Associations claimed that consolidating classes could have significant negative or positive bill impact on some customers. Commercial Associations referred to Docket Number 14965, *Application of Central Power and Light Company for Authority to Change Rates,* in which CPL sought to consolidate nine commercial rate classes into two rate groups. Nucor and

TXI (both TXU customers) stated that they support the retention of the existing rate classes for CTCs. Nucor and TXI argued that class consolidation would not solve migration problem. Nucor and TXI gave the example of the Instantaneous Interruptible (II) and Noticed Interruptible (NI) classes for TXU and stated that combining these two types of interruptible classes would result in II customers overpaying and NI customers underpaying their statutory CTC responsibility. OPC stated that it does not advocate ignoring the bill impacts of rate consolidation. OPC stated that concerns raised by TXI and Nucor regarding the distinction between II and NI classes should be considered. However, if, in the future, migration becomes a severe and real, rather than a hypothetical problem, class consolidation for CTC purposes is a reasonable option.

Relating to the customer migration to on-site generation or out of service territory, TXI stated that the commission lacks the ability to control these actions. Therefore, it is imperative that the benefits of under/over-recovery should be applied on a system wide-basis.

TIEC stated that *fixing* the initial allocated stranded cost dollar amounts as advocated by parties who support the *numeric approach* creates the problem of customer migration. According to TIEC, the best way to deal with the migration issue is not to fix the initial allocation amounts on a class basis. TIEC argued that consolidation is not a solution if fixed allocators are used. Consolidation would substantially eliminate any headroom for some customers and hinder the development of a competitive market. TIEC recommended that the way to minimize the adverse impacts of migration would be to: (1) make known and measurable adjustments to load data; and (2) cap the CTC for customer classes that may experience load shrinkage. Enron agreed with TIEC, and stated that consolidation of classes will not resolve the problem. Enron argued that historic classes should be maintained throughout the CTC collection period and urged the commission to adopt a provision in the proposed rules that would require a periodic review of the CTC collection by customer class to reconcile cost recovery with the initial stranded cost allocation.

OPC responded to TIEC stating that class consolidation could be a reasonable tool for smoothing out any adverse impacts of migration, if done carefully and thoroughly on a case-by-case basis. OPC argued that, over time, broadly similar groups of customers have been subdivided into increasingly narrow classes and riders in order to minimize rates for specific subsets of customers, rather than to serve any rate making principle. According to OPC, SB7 specifies a fixed allocation for the residential and non-firm classes. Commercial Associations also disagreed with TIEC and stated that the letter by the Legislators makes it clear that the non-firm class contribution should not decrease. Commercial Associations also objected to the adjustment to the allocation factor for customers leaving for eligible self-generation. Commercial Associations noted that the Legislature did not mandate a 6.0% reduction in rates for industrial customers, thus making them more attractive to REPs. OAG stated that customer migration should not be considered in developing the initial allocation factors, nor at the time of the true-up. According to OAG, once the allocation is set, it remains unchanged because SB7 permits the commission to adjust the CTC but not the allocation. OAG also referred to the letter from the legislators and commented that the Legislature's intent was not to allow system migration to be considered when developing the class allocation.

Cities agreed with TIEC and TXI that both class and customer impact should be considered in evaluating the merits of rate class consolidation. However, Cities argued that the emphasis placed on individual customer impacts by TIEC and TXI is misplaced and might preclude remediation of the hypothetical worst case scenarios that industrial customers claim. Cities objected to the tagging of customers and stated that it is likely to be administratively burdensome, perhaps even unfeasible. According to Cities, customer migration is not a new phenomenon and, in the past, a customer who migrated paid the rate applicable to the new class.

OPC suggested that inter-class migration could be resolved by transferring the customers' responsibility to the new class. According to OPC, this can be accomplished either through class consolidation or assigning each customer a fixed CTC responsibility based upon the customer's tariff as of a specific date. Relating to migration out of the system, OPC suggested confining loss to the original class and deferring class-by-class reconciliation until the true-up proceedings. For the extreme cases, OPC recommended limited consolidation among the similar major groups but objected to consolidation of the commercial group with any industrial groups.

CU/TLSC/Texas ROSE stated that by using the term *customer class*, SB7 plainly requires that once stranded costs are allocated to a class, the class would retain the responsibility for the stranded costs. TIEC disagreed with CU/TLSC/Texas ROSE's interpretation of PURA §39.253(i). According to TIEC, nothing in SB7 provides that the customer classes are defined in the utility's cost of service from the last rate case. It is unreasonable and without support in SB7 to argue that customers in a rate class today are responsible for stranded costs based on the composition of that class years ago. TIEC also noted that PURA §39.253(i) explicitly stated that "*except as provided by §39.262(k),* no customer or customer class may avoid the obligation to pay stranded costs" (emphasis added). According to TIEC, §39.253 and §39.262(k) are intimately tied together. Therefore, the characteristics of a customer class must be adjusted for customers that co-generate pursuant to §39.262(k). TIEC also stated that because §39.253(i) specifically refers to the obligation of *customers*, not just customer classes, this implies that specific customers should not have to pay more than their fair share. TIEC added that SB7 requires that the effect of stranded cost recovery on *customers*, not just customer classes, must be considered. Using historical allocators and not addressing migration seriously harms individual customers, thereby contradicting PURA §39.253(i).

Shell also objected to class consolidation to solve migration problems. According to Shell, SB7 does not allow the commission to adjust the stranded cost allocation. Even if an interruptible customer migrates to a firm class, it must still pay the CTC of the non-firm class, and therefore, migration does not represent a significant issue. According to Shell, the letter by the Legislators to Chairman Wood states that the issue and consequences of migration from any class of customers were not presented, discussed or debated in the committee or on the House floor, which makes this issue moot. Shell also noted that all the comments offered to fix the migration problem involve shifting stranded costs from the industrial class to the residential and small commercial customers. Shell suggested that the commission either should do nothing or implement tagging of customers to address this issue.

Enron stated that stranded cost responsibility should be based upon customer class assignment without consolidation of current rate classes. According to Enron, the CTC can be established on a per-customer basis, based upon the most recent forecast of the stranded cost allocation for the respective class. Enron argued that a customer should be able to pay off this amount any time during the period the CTC is in effect, based upon the present value of the stream of revenue that would be collected based upon the customer's usage reflected in the most recent CTC forecast. EGSI objected to Enron's proposal, stating that such a suggestion is fundamentally inconsistent with SB7 and should be rejected.

The commission concludes that no change to the proposed rule is necessary. It is not feasible to specify rate class consolidation in the rule because migration and load loss will be different for each utility. However, the commission finds that class consolidation may be necessary to facilitate implementation of the CTC and to avoid future problems arising from migration. Furthermore, while the commission agrees that it is important to evaluate the bill impacts of class consolidation, to require that any customer (as opposed to class) not be materially disadvantaged by consolidation may well make it impossible to consolidate any classes. The language in proposed §25.345(j) is flexible enough to allow rate class consolidation to be decided on a utility-by-utility basis after proper evaluation of the potential customer and class impacts with respect to customer bills and the price-to-beat. The commission rejects Enron's suggestion to allow a customer to pay off stranded costs in advance (by paying the net present value of the future CTC's). This method was never discussed in any of the workshops. In addition it would be administratively very difficult, if not impossible, to quantify the stranded costs obligation of a customer over the life of the CTC. No change was made to §25.345(j).

Fourth question:

How should the existing rates and riders be consolidated for the purposes of transmission and distribution charges?

CU/TLSC/Texas ROSE stated that it is important to retain existing low usage and low income rates and riders and suggested language be added to proposed §25.344(j) to clarify that low income and low usage customer classes should not be materially disadvantaged by class consolidation. Additionally, CU/TLSC/Texas ROSE proposed language requiring utilities to offer transmission and distribution and CTC rates that encourage energy conservation through lower rates to those customers who fall within the lowest 25% of residential consumption levels.

Commercial Associations stated that no consolidation of classes should occur because of the likely disparate effects on customers. Nucor stated that it believes the statute requires the retention of existing classes for CTC recovery. As such, for those utilities that have stranded costs, Nucor suggested that the consolidation of transmission and distribution rates into a smaller number of classes than CTC classes would be confusing. Nucor suggested that class consolidation could be considered for utilities without CTCs or when the CTC recovery expired, as long as voltage and firmness differences were accounted for and no class was materially harmed. TXI commented that to the extent that class consolidation occurs, it should be minimal. TNP suggested that, at a minimum, cost causation should drive class consolidation. The smallest number of classes should be residential, commercial, and large commercial/industrial; there should be no more classes than the current number.

PG&E commented that the commission must ensure that the consolidation of transmission and distribution rates does not result in any class having a sum of non-bypassable charges and the expected market price for power that exceed the price to beat.

TXU suggested that transmission and distribution classes of residential, commercial and industrial ("general service") and lighting be established. The "general service" class would be further subdivided by voltage level.

Shell, CSW, TIEC, Cities, and OPC stated that class consolidation should not be expressly defined in this rule, but instead considered in the cost separation proceedings.

EGSI agreed with proposed §25.344(j) but stated that a somewhat different approach may be needed for each utility in order to mitigate negative effects on customers.

Enron stated that CTC classes should only be consolidated if the stranded cost obligation of the classes does not change. Additionally, Enron argued that the consolidation of classes for the purposes of transmission and distribution rate design may harm the ability of REPs to offer rate comparisons before and after customer choice is introduced. Enron also stated that the commission should initiate a proceeding upon expiration of the CTCs to change the utilities' rate structures in order to develop pricing based on REPs' aggregate load. Reliant filed similar comments stating that class consolidation should only occur to the extent that cost causation is common between the rate classes and that the price to beat regulation on the affiliated REP should be considered when determining which classes should be consolidated.

TIEC stated that certain general principles should be followed in determining how existing rates should be consolidated, including cost causation, price signals, accommodation of existing meters, and consistency with Public Utilities Regulatory Policies Act (PURPA). Additionally, TIEC stated that PURPA requires a separate transmission and distribution rate for standby and non-firm delivery service. In their reply comments, Shell, Cities, and OPC disagreed with TIEC's suggestion to implement a non-firm or interruptible transmission service for standby and non-firm customers. They all stated that there is no reason to create such a service. Interruptible service is a generation issue and not a transmission congestion management strategy. Putting special discounted T&D rate classes in place is incompatible with the market. Cities pointed out that significant cost avoidance through an offering of interruptible service is unlikely and benefits are unlikely to exceed the cost of discounts. OPC also pointed out that the postage stamp pricing of transmission service required by SB7 does not exclude the full responsibility of non-firm generation services' use of the transmission system. In addition, OPC disagreed with TIEC on PURPA's requirement that non-firm standby services should be available to Qualifying Facilities (QFs). OPC believed that this requirement is applicable to a fully bundled standby rate but not the T&D component of the standby rate.

Cities stated that, to the extent current classes are consolidated, it is more reasonable to combine them into classes based on usage-related variables, such as load factor, usage, and seasonality, rather than arbitrary distinctions such as whether the business in question is considered to be a commercial or industrial application.

SPS stated that transmission and distribution rates should be largely based on voltage and kVA capacity and the structure of these rates should be composed of a fixed charge plus demand charges. SPS also maintained that transmission rates should be consistent with the open access transmission tariff on file at the Federal Energy Regulatory Commission (FERC), because the distribution system is primarily constructed to meet peak conditions.

The commission concludes that no change to the proposed rule is necessary. The commission agrees with many commenters that the class consolidation should not be expressly defined in this rule, but instead addressed in the cost separation proceedings. The commission believes that the language included in the proposed rules allows for enough flexibility for the commission to resolve the class consolidation issue in the April 2000 cost separation cases. However, the commission also believes that the customer classifications from the traditional regulatory paradigm will be less relevant in a competitive marketplace than they are today. Some degree of class consolidation needs to be in place to reflect the new competitive paradigm and to foster the development of the competitive market as envisioned by the statute. For the duration of the price to beat period, however, special attention should be given to the protection of the headroom consistent with the commission's future decisions on the implementation of the price to beat provisions of SB7. The commission agrees with Enron that it may be useful to alter the design of non-bypassable charges and classes after the expiration of the CTCs in order to bill REPs on their aggregate load. However, such pricing may adversely affect the attractiveness of customers under price to beat regulation. Additionally, it is not appropriate at this time to address the need for low-income rates because they will be funded through the System Benefit Fund. Regarding energy conservation rates, the commission is implementing, through Project Number 21074, an energy efficiency mechanism to fund programs to reduce demand. It is not appropriate to vary from cost causation principles in the design of rates to incent this goal when there is direct statutory authority to develop an explicit subsidy program. Regarding standby and interruptible rates, the commission observes that bundled standby and interruptible rates are frozen until competition begins. Beginning January 1, 2002, a utility will only be providing regulated wires services. It is not clear why there will need to be different transmission and distribution rates depending on the nature of the generation service being sought. To the extent interruptibility adds value to the transmission system, this may be reflected through other mechanisms. Section 25.344(j) has therefore not been changed.

Fifth question:

What rate design for non-bypassable charges facilitates simple billing to retail electric providers while also preserving a reasonable "shopping credit" under the price to beat?

CU/TLSC/Texas ROSE and SPS suggested that non-bypassable charges should be minimized, clearly disclosed to retail customers, and collected on a cents-per-kWh basis to facilitate comparisons. Cities concurred with respect to residential customers. Additionally, SPS stated that REPs should bill end-use customers and remit the revenues to the T&D utility. Nucor stated its support for simple energy charges, with such charges varying by the customers' class of service and reflecting the costs allocated to that class.

PG&E stated that it is crucial that transmission and distribution rates be designed from the "bottom up", but that a myriad of other factors outside the scope of this proceeding make this a difficult question to answer now. PG&E suggested that the question continue to be addressed by the rate design task force. EGSI and Reliant commented this question is better addressed in the cost separation proceeding, on a utility-specific basis, in order to recognize differences.

TXU, CSW, Reliant, and TNP stated that the rate design for non-bypassable charges should be similar to the existing rate structure. Cities concurred with respect to commercial and industrial classes. Additionally, TXU stated that the charges should consist of a fixed charge for customer-related costs, a facilities charge for transmission and distribution investment, and a variable charge for stranded cost charges and system benefit fund (SBF) charges. Both Enron and OPC stated, in their reply comments, that there is little benefit in changing the rate structure for residential and small commercial customers while the price to beat is in effect.

OPC stated that the CTC for commercial and industrial customers should utilize the current proportionate split of production costs between the demand charge and the energy charge in order to prevent a shifting of cost between customers with different load factors. Additionally, OPC stated that the residential CTC should be an energy charge, with seasonal differentiation if necessary. OPC also stated that energy charges should be used for transmission and distribution rate design for residential customers. TXI disagreed with OPC and believed that, since the stranded plant costs are demand-related costs, the CTC should be a demand-based charge.

Commercial Associations stated that cost of service principles should dictate rate design, and that CTC design should mimic the existing rate structure. Enron stated that the CTC design must follow the cost causation and allocation methodology applied to develop the ECOM amount for each customer class. The SBF should be a fee based on kWh used, and transmission and distribution charges should be designed in the same manner as that approved in the utility's most recent cost study or rate order.

TIEC stated that rate consolidation for the CTC could substantially eliminate the shopping credit for some classes and that a stable CTC should be designed to recover stranded costs over the shortest time period possible.

The commission concurs with those parties that have suggested that the cost separation and securitization proceedings are the appropriate venues to address the proper rate design of non-bypassable charges. At that time, the commission can more fully investigate the potential impact on customers of different usage levels, load factors, and types of service as well as ensure that the rate design of non-bypassable charges does not adversely affect the margin under the price-to-beat for those customers subject to price to beat regulation.

Sixth question:

What level of interaction should the transmission and distribution utility have with the end-use customer? For example, should end-use customers be able to contract and be billed for transmission and/or distribution services, directly from the T&D utility, or should all *procurement of T&D service be through the customer's REP? Additionally, are there services for which the T&D utility should directly bill the end-use customer, and if so, does the T&D utility therefore need to retain a customer collections function?*

CU/TLSC/Texas ROSE commented that the interaction between the T&D utility and end-use customers should be limited to the contact necessary to perform traditional transmission and distribution services (including connections, line extensions, and service restoration) and should occur through the customer's REP. The T&D utility should be responsive to customer requests for regulated services and should not solicit subscribers for services. CU/TLSC/Texas ROSE also stated that it was the intent of the Legislature to have all billing occur through the REP, and thus, there should not be any billing by the T&D utility to an end-use customer. PG&E agreed that the T&D utility should have minimal or no interaction with the end-use customer, but that billing to the end-use customer by the T&D utility should be done only at the request of a customer's REP.

Nucor, TXI, TIEC, and OPC stated their belief that the statute clearly allows for end-use customers to contract directly for transmission and distribution services after January 1, 2002 and that this provision is crucial to customer choice and ensuring a vibrant competitive environment. However, OPC clarified that this should be the same rate as is applicable to a REP and not customer-negotiated transmission and distribution rates. OPC also stated that aggregators may need to separately arrange for transmission and distribution services and should be able to arrange for alternate billing arrangements as well. In addition, in its reply comments, OPC believed that the suggestion that only industrial customers or customers who meet a size threshold can directly arrange for transmission service is not supported by SB7. Shell disagreed with Nucor, TXI, TIEC, and OPC and stated that their suggestion that the statute permits end-use customers to obtain transmission and distribution service fail to read the statute in context. The only interpretation to harmonize all relevant sections is that the REP is the end-use customer's agent under all situations.

EGSI commented that PURA, and the legal relationship between the customer and the utility, should govern the level of interaction between an end-use customer and the T&D utility. Requirements for service quality standards that the T&D utility must meet suggest that the T&D utility does have a direct contractual relationship with end-users, but that REPs have billing and collection responsibility for customer charges. EGSI also stated that there are instances where the T&D utility will need to have contact with the customer. EGSI commented that FERC orders and rules would ultimately control the level of interaction between end-users and the transmission company.

TXU and SPS stated that, in some instances, a customer should have the choice of whether they contact their REP or the T&D utility (such as outage orders, service orders, service upgrades, construction requests, etc.). In other cases, customers are likely to only contact the T&D utility (such as tree trimming, feeder maintenance, outage restoration, etc). TXU and SPS further stated that the code of conduct will provide adequate protection to ensure that the T&D utility does not engage in any activity that gives preference to its competitive affiliates. In its reply comment, Shell stated that the T&D utility does not need to interact with end-use customers concerning outages and service interruptions. Many REPs already have and will have the system and ability to report the outages to the T&D utility. The T&D utility should focus its effort to correct the outage problems and limit its cost imposed on its non-bypassable rates.

Shell and NewEnergy stated that the T&D utility should only be contacted in the case of emergencies. Additionally, Shell stated that the type of interaction discussed by TXU would lead to confusion and frustration on the part of customers.

TNP stated that the T&D utility should retain many of the same services currently provided by the integrated utility, and should be able to bill the end-use customer directly for them. TNP argued that this would ensure a transparent transition to competition, as well as recognize the right of customers to continue with the status quo with respect to certain services.

Enron stated that the T&D utility ought to only interact with end-use customers in order to provide tariffed services that are impractical to offer through the customer's REP. Enron also stated that the costs of billing these services to customers should not result in increased costs above the cost to provide system services. In its reply comments, Enron stated again that any system that a utility purports to be necessary to ensure recovery of non-bypassable wires charges from end-users is inappropriate and must not be allowed for inclusion in the utility's transmission and distribution rates.

CSW and SPS stated that, in general, the customer should contract and arrange for T&D services through their REP, but could be allowed to go directly to the T&D utility for discretionary services and be billed directly. Shell stated, in its reply comments, that this suggestion ignores the statute and presents a potential for competitive abuse.

Reliant and SPS stated that customers should in no way be precluded from contacting the T&D utility, as quite often it will be this entity that can most efficiently answer customer questions and resolve their concerns. Reliant also commented that new customers would likely find it much easier to contact the T&D utility for the commencement of service than a REP. Additionally, the T&D utility must always have a billing and collection function for billing of the relocation of facilities, damage done to utility equipment, or other services. Reliant stated that while in most cases, all interaction will go through a customer's REP, the commission should not restrict the customer's ability to choose to contact the T&D utility when customers believe it to be proper.

SPS also stated that the T&D utility should be allowed to conduct public safety advertising.

TIEC stated that certain industrial customers with excess generation on site may want to transport that generation to another site in the retail choice environment. These customers should be able to procure transmission and distribution service without going through a REP. Other customers who want to contract separately for transmission and distribution service should be able to do so and the REPs could perform the billing for such services. OPC disagreed with TIEC and stated that SB7 imposes a structure which requires all retail electric transactions to be made by a Retail Electric Provider and which precludes power generation companies from making sales to retail end-users.

Cities stated that T&D utilities should be restricted to only offering regulated, tariffed services consistent with the code of conduct.

The commission believes that, as a general rule, the primary point of contact for customers should be the REP, which should be the primary procurer of T&D services. Having a single point of contact for electric services will cause less customer confusion and encourage REPs to compete for customers on both price and service quality. Removing the retail customer contact from the T&D utility was a significant part of the recently completed code of conduct rulemaking in Project Number 20936, *Code of Conduct for Electric Utilities and Their Affiliates*. While it may be true that in some emergency situations, the customer may need to directly contact the T&D company, this is not sufficient justification for requiring a customer to contact multiple entities to resolve problems, nor is it justification for T&D utilities to continue to maintain large and costly customer call centers and billing systems. Larger customers with unique distribution facility needs may choose to deal directly with the T&D utility on certain T&D utility service issues. Nothing in this rule should be read as precluding that contact to meet these unique distribution needs, so long as the utility observes the code of conduct and the REP is notified. The specific parameters of the T&D utility-REP-customer relationship will be established in the forthcoming rulemakings implementing REP qualifications, standard statewide T&D utility tariffs, and customer protections. As such, no change to the proposed rule is needed.

Seventh question:

After customer choice is introduced should a T&D utility be able to provide an energy service that is capable of being provided by a competitor if it is not widely available?

EGSI, Reliant, CSW, and TXU commented that the T&D utilities should be able to provide energy services that are not widely available after the introduction of customer choice. The utilities commented that it follows from the statute that, if a service is not widely available, then a utility may provide the service both after September 1, 2000 and after January 1, 2002. PG&E responded that utilities failed to advance any valid reasons why their affiliated REPs could not provide these same services. PG&E postulated that the utilities intend to charge incremental costs for these services in transmission and distribution rates. TNMP and CSW commented that many rural customers will not have a choice of provider for many of the services listed in the proposed rule, and should be given the option of retaining the T&D utility for services that they cannot receive elsewhere. In response, PG&E commented that these arguments are based on speculation, without reference to any situation. PG&E further replied that, during the transition period, T&D utilities will presumably be providing non-widely available competitive energy services to these customers. Therefore, the commission could address these concerns in the light of actual experiences during the transition period. In response to EGSI, TNMP, TXU, CSW, and Reliant comments, OPC stated that the utilities' response ignores the necessity for a petition; therefore, the proposed rule should remain as published.

TXU commented that neither the Utilities Code nor any other state law has historically precluded an electric utility from providing unregulated services. TXU further commented that T&D utilities should also be able to continue to provide transmission voltage wires-related services.

CSW commented that the intent of SB7 was to require separation of these activities, not to prohibit a T&D utility from engaging in these activities. Enron replied that TXU's interpretation of the existing law and the purposes of SB7, to allow the provision of services (other than the sale of electricity) by the regulated utility without regulatory oversight, is "wholly without merit" and should be ignored by the commission. Enron also commented that the commission should require that any product or service offered under the name of the utility be offered subject to an embedded cost-based tariff.

EGSI suggested that if a party believes an energy service should be declared competitive after customer choice is introduced, such party should have the initial burden of proving that the service is widely available. OPC responded to EGSI's comment by stating that it is a barrier to entry for competitive energy service providers to have to prove that for a competitive energy service and such requirements should be dismissed.

Reliant commented that precluding the utility from offering an energy service that is not widely available could provide a single other participant or service provider with a dominant and powerful position approaching monopoly status. OPC stated that accepting Reliant's proposed changes in the area of competitive energy services ensures that the T&D utility will be a single, dominant provider and will guarantee its monopoly status. PG&E replied that Reliant misapprehends a fundamental tenet of SB7: that the "normal forces of competition" can more efficiently determine the price and availability of competitive energy services. Furthermore, PG&E replied that Reliant and most other utilities ignored the issue that its own competitive affiliate can provide any needed competition with unaffiliated REPs or competitive service companies. Cities replied that they do not want to replace one monopolist with another; however, there is good reason to minimize T&D utility offerings of potentially competitive services.

Nucor commented that the T&D utility should be required to provide products and services the commission deems essential pending the availability of a truly competitive market for those products and services, such as ancillary services and load control programs. (For example, the spinning reserve component of instantaneous interruptible service provides transmission and distribution benefits and should continue to be offered by the T&D utility after the implementation of customer choice). Cities replied that the competitive market should determine the value of interruptible service.

SPS commented that T&D utilities should not provide competitive energy services after the introduction of customer choice. PG&E commented that proposed §25.342 should prohibit a T&D utility from providing any energy service that is capable of being provided by a REP after the introduction of customer choice on January 1, 2002, regardless of whether the service is widely available. Reliant replied that PG&E's comments greatly expand upon the requirement of PURA §39.051(a).

Cities, Enron, OPC, Shell, TESCO/ TACCA/IEC, TIEC, CU/TLSC/Texas ROSE, and NAESCO commented that T&D utilities should be able to petition the commission under §25.343(d) for approval of a tariff to provide an energy service that is unavailable through a workably competitive market. Shell further stated that if any entity offers a competitive energy service, the service is "widely available". Shell suggested that allowing a regulated utility with a captive customer base to enter a competitive electric service market would tend to inhibit competition in that market. TESCO/TACCA/IEC suggested that many potentially competitive services may not be widely available in the competitive market today, simply because utilities have offered such services in the past. TESCO/TACCA/IEC commented that they agree with the approach of the proposed rule, which places the burden of proof on the utility to show that a potentially competitive service should be provided by the utility after competition is introduced. TIEC commented that the commission should establish objective criteria to determine whether a specific energy service is "widely available" under SB7. TIEC recommended that an energy service be classified as being widely available if there were one or more existing competitors in a region that are capable of providing the service. In response to TIEC's comments, Cities commented that they do not want to deny service where acceptable available alternatives do not exist, but agreed with TIEC that all transmission and distribution services should be tariffed. NAESCO commented that the rule should not distinguish between the transition period that begins September 1, 2000 and the customer choice period that begins January 1, 2002. NAESCO suggested that at either time, a utility should not be allowed to provide an energy service unless it can prove that the service is not widely available, as a result of barriers beyond the control of either the utility or the commission.

The commission declines to change proposed §25.343. The commission finds that a T&D utility may provide competitive energy services that are not widely available under proposed §25.343(d)(1) after the implementation of customer choice pursuant to a commission-approved tariff. The commission disagrees with PG&E's proposal to restrict the T&D utility from offering such competitive energy services after the transition period. While the commission is committed to the creation of a robust competitive energy services market in Texas, the commission also believes that this market may not materialize simultaneously for all electric customers in Texas, particularly rural customers. Therefore, adopting extensive restrictions on the provision of competitive energy services is not necessary and might harm customers. The commission believes that proposed §25.343 sufficiently allows both utilities and other affected parties to petition the commission regarding the provision of competitive energy services. The commission finds that the proposed petition system strikes a proper balance between the creation of a robust competitive energy services market in Texas and the continued availability of competitive energy services to customers. The commission also believes that the petition system is a dynamic process and allows the commission sufficient discretion to promptly address issues relating to competitive energy services as they arise.

Eighth question:

Are there any circumstances, such as reliability concerns, under which an electric utility should be able to provide a widely available energy service after September 1, 2000?

EGSI, SPS, and TXU commented that reliability concerns and transitional issues should be considered when the commission is evaluating a utility's petition to provide competitive energy services. For example, EGSI commented about the impact of third party offers of non-roadway security lighting on the continuity of safe and reliable service for its customers. CSW stated that impacts on reliability should be considered when determining whether a T&D utility is allowed to provide a widely available competitive energy service. CSW commented that such services include, but are not limited to, customer premise power quality issues, transformer emergency services, and technical assistance relating to any device a customer may install on their premises that is likely to affect transmission and distribution system reliability, safety, or efficiency. Reliant stated that it is not in the public interest, nor was it the intent of the Legislature, that reliability and the utilities' ability to meet customers' consumption demands be compromised. OPC replied that only in the event that the relevant service is not available in a given area can the electric utility offer such service, and then only after petitioning the commission. PG&E responded that it is not opposed to T&D utilities providing competitive energy services to the extent necessary to protect public health and safety during emergencies. However, the commission should make clear that competitive energy services to ensure grid reliability do not permit the T&D utility to provide competitive energy services to an end-user's facilities in non-emergency situations, even if necessary to ensure grid reliability. PG&E further replied that customer-premises facilities must be designed to meet specifications set forth in an interconnection agreement with the T&D utility. Therefore, the T&D utility already has the means to ensure that customer-premises facilities are designed and maintained in a manner that does not impair the reliability of the T&D utility's system.

Nucor stated that valid reliability concerns would justify an electric utility or a T&D utility offering a potentially competitively available energy service. Nucor suggested that a utility might need to offer other load management programs to ensure cost-effective reliability, due to the lack of a fully developed market for these services. OPC stated that it strongly opposed electric utilities offering load management and other demand-side management programs that could be provided by the market. SPS commented that the regulated utility will need to provide many widely available services during the transition, which, if prohibited, will deny services to customers. TNMP commented that in order to ensure that the level of service customers are receiving today does not deteriorate, the T&D utility should be allowed to petition the commission to provide the services under a regulated tariff. Shell stated that PURA §39.051(a) provides no exceptions for reliability, or any other considerations. In response to examples illustrated by certain utilities, Enron commented that the commission should disregard the nonspecific, unproven claims of need proffered by the utilities, and maintain the rule language.

OPC and Shell commented that they could envision no circumstances under which a T&D utility would need to provide services that were actually widely available. Shell stated that SB7 does not allow an exception for reliability concerns, and a utility could, in fact, link virtually any action in some respect to reliability concerns. EGSI responded that these arguments should be rejected because such arguments prevent the commission from addressing public interest-type concerns such as transitional issues and reliability concerns identified by EGSI. CU/TLSC/Texas ROSE suggested that nothing prohibits a T&D utility from taking cost-effective steps to improve system reliability through competitive energy service providers or to petition the commission for an exception under §25.343(d) of the proposed rule. NAESCO commented that the rapid and widespread development of competitive markets for energy services requires that utilities not be allowed to provide such energy services. PG&E commented that any reliability exception to proposed §25.342(d) should be limited to addressing electric grid reliability concerns, not customer-specific concerns, and should be offered only during the transition period. PG&E proposed a new paragraph, §25.343(d)(3), which establishes a petition provision for utilities to provide competitive energy services to address grid reliability concerns during the transition period. TXU replied that any wires-related service that is to be provided should not be restricted to the transition period, and should be deleted if the language is adopted by the commission. TXU further commented that the proposed language should not serve as an impediment to a T&D utility providing reliability-related services to other T&D utilities (for example, loan of emergency service restoration crews during weather-related emergencies).

Enron commented that proposed §25.343(d) specifies the conditions under which a utility may render competitive energy services. Enron suggested that if the utility can demonstrate that any service is necessary to the integrity of the T&D utility, that service must be provided under an approved cost-based tariff. TIEC stated that any such circumstances should be strictly limited, and should be eliminated on January 1, 2002. TIEC suggested that any such exceptions should be restricted to situations in which the utility can demonstrate that the service cannot be transferred to its affiliated REP or auctioned to an unaffiliated REP by September 1, 2000. Enron agreed with TIEC's, Shell's, and OPC's comments, which place the requirement on the utility to show that an energy service provided for reliability concerns is necessary for the provision of transmission and distribution services.

The commission declines to change proposed §25.343 in response to comments issued for this preamble question. The commission finds that reliability services provided by the regulated utility for the operation and maintenance of and interconnections to the transmission and distribution system will continue to be regulated services provided by the electric utility. These services do not fall under the definition of competitive energy services. Proposed §25.343(c) states that competitive energy services are prohibited from being provided by the regulated utility. While the commission agrees that reliability of the transmission and distribution system should be maintained in Texas, the commission is not persuaded that the provision of widely-available competitive energy services by the regulated utility is necessary for maintaining system reliability. At this time, the commission cannot envision any widely available competitive energy services that if not provided by the regulated utility would compromise system reliability.

TXU also commented that T&D utilities should be able to perform their obligations under existing contracts with customers. PG&E replied that the commission should, at the very least, add a provision to the proposed rule which prohibits T&D utilities from entering into new contracts or renewing contracts for competitive energy services effective September 1, 1999.

The commission concludes that the regulated utility is required by law to separate competitive energy services from its regulated activities effective September 1, 2000. Contracts which predate the effective date of SB7 must be reformed to comply with this requirement. Any contract entered after the effective date of SB7 is executed under the requirements of this separation. Consequently, the commission finds that it is unnecessary to prohibit by rule the entering into contracts that are contrary to the separation requirement.

Ninth question:

If the commission allows utilities to petition to provide energy services that could be provided by a competitor but are not yet widely available, should the permission to provide these services be for an express period of time?

EGSI, Reliant, and TNMP suggested that specifying a time period would be unnecessary, because the proposed rule establishes a procedure for reclassifying, as a competitive energy service, a service that is being provided by a utility. EGSI commented that establishing a time period would require unnecessary legal proceedings to continue the service. TXU commented that each petition should be considered on case-by-case basis. TXU recommended that once the utility proves that a service is not widely available, the assumption should remain that the service is not widely available unless and until entities wishing to provide that service establish to the commission's satisfaction that such entities are ready, willing, and able to provide the service in question. CSW commented that specifying a time period would not be an efficient use of resources. CSW suggested that the petitioned service should remain in effect until the commission discontinues the petition. OPC replied that time limits are good public policy and consistent with PURA; without time limits, a T&D utility may erect barriers to entry and prevent the formation of competitive markets. Shell replied that failing to adopt a specific expiration date for a utility's petition to provide a competitive energy service will discourage small businesses from entering the market and stifle the competitive energy services market.

Nucor stated that the commission could set periodic dates for reviewing petitioned services and discontinue a petition only when available competitive alternatives emerge. Nucor commented that customers should be allowed to petition the commission in order to require the utility to provide such services as appropriate. SPS commented that these services should be provided under tariffs that have a certain expiration date. Cities commented that a tariff authorizing an energy service to expressly terminate after three years, and the T&D utility could re-apply for the service. Enron, Shell, TIEC recommended that the time period for offering a petitioned service should be limited to one year with the utility affirming year-to-year that the petitioned service is not widely available. NewEnergy suggested that, if the commission allows this treatment, it should not only limit the services to an express period of time, but should also limit the region to which the services are provided. OPC supported a time limitation in order to restrict the monopoly ability to exert market power in emerging markets. TESCO/TACCA/IEC and CU/TLSC/Texas ROSE commented that each petition should be required to establish a reasonable period for such service, which should be the subject of the petition proceeding. In the alternative, CU/TLSC/Texas ROSE recommended that some criteria be established to monitor and determine when the T&D utility's involvement in the provision of the service is no longer necessary. NAESCO commented that a time limit should be established for not longer than two or three years. PG&E commented that the utility provision of competitive services that are not widely available should be limited to the transition period. PG&E stated that if the commission determines that T&D utilities should have a right to provide non-widely available competitive energy services after the implementation of customer choice, such right should be limited to the lesser of one year, or the date that a non-affiliated REP notifies the commission that it has been or promptly will commence providing the same or substantially similar competitive energy service within the same market or portion of the market. Reliant replied that any time limitation is arbitrary and unnecessary. In its reply, Reliant commented that if the commission deems that a time limit is necessary, it should be decided on a case-by-case basis.

In its reply comments, Enron recommended that the commission implement procedures that require both a showing by the utility that the product or service is not widely available and implement a complaint process to cancel a competitive energy service tariff, as suggested by Cities.

The commission concludes that the establishment of a two year time limit for a commission-approved petition under §25.343(d)(1) is reasonable and in the public interest. The commission believes that the utility's provision of petitioned services should be self-expiring after two years unless the commission approves a new petition from the utility to continue providing the competitive energy service as a petitioned service. The commission adopts new §25.343(d)(1)(C) as follows: "The utility's petition to offer a competitive energy service terminates two years from the date when the petition is granted by the commission, unless the commission approves a new petition from the utility to continue providing the competitive energy service." The commission also notes that proposed §25.343(d)(2) allows for an affected person or the Office of Regulatory Affairs to file a petition to end the designation of a commission-approved utility petition to provide a competitive energy service. Therefore, these parties have the ability to limit the time period over which the utility may offer the petitioned service.

For purposes of administrative efficiency, the commission also adopts a new subparagraph under subsection (d)(1) establishing a notice provision for the affected utility. This provision ensures that adequate notice be given by the utility of its petition to provide a competitive energy service.

The notice must be made through a well-circulated newspaper publication in plain language throughout the service area affected by the petition. In the event that no affected party or the Office of Regulatory Affairs files an objection to the utility's petition within sixty days after the petition is filed with the commission, the petition shall be deemed approved for two years.

Tenth question:

After September 1, 2000, should an electric utility or a transmission and distribution utility be permitted to engage in economic development and community support activities? If so, should there be limitations on what they can do? Should the cost of engaging in such activities be recoverable from ratepayers?

EGSI, CSW, Reliant, EPE, SPS, TXU, Nucor, TML, and TNMP stated that T&D utilities should be able to continue to offer, and recover costs through customer rates for economic development and community support activities after September 1, 2000. Reliant, EPE, CSW, and TXU commented that the only limitations necessary on these activities are those prescribed by §25.272 (relating to the Code of Conduct for Electric Utilities and Their Affiliates). EGSI stated that these activities should remain with the regulated utility because (1) integrated utilities have traditionally been a partner in economic development with state and local entities; (2) the distribution utility is the only entity with ties to the service territory; and (3) it is in the public interest to promote more effective uses of resources and reduce average per-unit costs, thereby benefiting all customers. In response to EGSI's second point, OPC disagreed that REPs will not have ties to the areas where their facilities are located, and said it is absurd to suggest that businesses have no interest in the welfare of the communities where their plants and facilities are located. In response to EGSI's third point, OPC replied that the T&D function will be separated from the generation function and there will not be any relation between generation capacity and the provision of T&D service; therefore, there is no logical reason for T&D utilities to claim that their customers benefit from the reduction in excess capacity that may exist on an affiliate's generation system. NewEnergy commented that none of the parties in support of allowing the regulated utility to recover these costs addressed the important issue of the competitive advantage a utility's affiliate gains by providing these services. Shell asserted that continued subsidization of these activities through utility's rates would create "goodwill" for the affiliated REPs, increase non-bypassable rates, and disadvantage non-affiliated REPs entering the competitive market.

TXU suggested that REPs would have little incentive to engage in the types of economic development and community support activities that T&D utilities perform today. Therefore, if these activities are prohibited from being offered by the T&D utility, then communities will needlessly suffer. OPC replied to TXU by stating that REPs themselves have commented in this proceeding that they have a strong interest in being involved in economic development activities. Enron and Shell strongly disagreed with the parties' assertion that without the T&D utility's support, economic development in communities would not exist. Enron stated that the creation of jobs and the ensuing prosperity of any community are created by the actions of the competitive market and not the local utility. Enron further stated that T&D utilities should be allowed to support economic development through shareholder funds, provided that the funding does not influence customers in the selection of their REP.

Reliant commented that economic development is one mechanism for a utility to increase its customer base by bringing in more people into its service area; without these activities, growth of its core business is limited. OPC replied that the utility's desire to expand its business is primarily driven by stockholders' desire to see increasing dividends and earnings; therefore, shareholders should fund these activities. Reliant further suggested that because of its long-term partnership in the community, a utility is better able to provide community support activities, such as aiding low-income customers with electric service problems and ability to pay bills, that help resolve the immediate needs of its residents. OPC responded that Reliant's arguments incorrectly assume that the T&D utility must help solve the REP's customer problems because Reliant's assumption is not consistent with SB7.

CSW commented that economic development is not an "energy" service and, therefore, should not be considered to be a competitive energy service under the proposed rule. No provision of service or sale of electricity to a customer is involved in this effort that is capable of being tariffed. CSW also stated that the reasonableness of these activities' costs could be addressed at the time of the cost separation proceedings. OPC replied that the issue is not whether these activities are "energy services" but whether T&D utility customers should be forced to pay for these activities. Furthermore, OPC noted that CSW provided no explanation of why these activities should be considered transmission and distribution services.

EGSI commented that the requirement that these activities be "specific to transmission and distribution" is vague and provides no guidance. EGSI also stated that the phrase "do not benefit the utility's affiliate" is beyond the statutory language, and suggested the language "does not give preferential treatment to the utility's affiliate," which conforms to the statute.

NewEnergy, Shell, Cities, TIEC and OPC commented that it is inappropriate to permit T&D utilities to engage in economic development or community support activities, unless those activities are funded exclusively by utility shareholders. OPC stated that the ability of the regulated utility to charge its ratepayers for these expenses would put non-affiliated market participants at a substantial competitive disadvantage, which is specifically prohibited by PURA §36.157. PG&E commented that the utility should be able to recover the costs of engaging in commission-approved community support and economic development activities, only to the extent the activities are directly related to the transmission and distribution functions. TIEC and Shell commented that under no circumstances should T&D utilities be permitted to recover the cost of such activities from their regulated rates. CU/TLSC/Texas ROSE commented that economic development is a marketing activity and is an inappropriate activity for a T&D utility. Shell commented that economic development activities present affiliate abuse concerns because allowing a T&D utility to continue to perform this function will permit it to generate goodwill for its affiliate REP with the same brand name, while billing the costs to retail customers. TXU replied that parties' concerns over affiliate abuses and anticompetitive behavior are addressed within the commission's Code of Conduct rules and further restrictions would both defeat the purpose of the Code of Conduct rules and limit the benefits of economic development activities.

The commission concludes that economic development and community support activities are not competitive energy services per se and has revised the language from §25.341(6) accordingly. In general, competitive energy services provide customer benefits related to the use of energy. However, economic development and community support activities are not reflective of other competitive energy services activities in that these activities relate mostly to the provision of non-energy services and information.

In that regard, a utility shall be permitted to engage in economic development and community support activities provided that such activities: (1) do not promote the provision of a competitive energy service (particularly one being provided by the utility's affiliate), (2) are conducted in a manner consistent with the code of conduct, and (3) benefit the utility's customers. Activities intended to attract new business to the community are considered to be such a benefit, since they increase the base over which a utility's costs are shared.

A further question arose regarding cost recovery for any of these activities. In its April 2000 rate filing, any utility seeking cost recovery of any of these economic development and community support activities, shall provide a listing and description of the activities it has supported in the past using regulated revenues for which it wishes to continue to seek cost recovery. If any party objects to such cost recovery, the utility shall demonstrate that its contribution to such programs is consistent with the three standards above, and are at reasonable levels. If the amounts included are at or below levels previously included in utility rates, they shall be presumed reasonable.

Eleventh question:

What, if any, bright line standard(s) could the commission incorporate in the rule to delineate the education, advertising, and economic development and community support activities that an electric utility or a transmission or distribution utility can do after September 1, 2000?

EGSI and CSW commented that no bright line standards should be imposed in these rules. EGSI and Reliant suggested that, if limits are placed on these activities, the limitation should reflect standards that already exist in PURA and in commission rules. CSW commented that T&D utilities should continue to provide education and advertising that: (1) supports the T&D utility's business functions (safety, outage information, and connects/disconnects), and (2) expressly informs entities such as energy service providers and contractors about the T&D utility's energy efficiency programs available through standard offer and market transformation programs. PG&E replied that CSW's comments should be addressed in Project Number 21074, *Energy Efficiency Programs,* and Project Number 21251, *Development and Implementation of a Customer Education Plan*. PG&E further stated that the commission should ensure that the utilities do not engage in providing competitive energy services under the guise of administering energy efficiency programs. Reliant stated that the reasonableness of these activities' costs could be addressed at the time of the cost separation proceedings. SPS commented that the commission should prohibit a delivery utility from favoring an affiliated REP's services. TXU stated that the commission should incorporate a "reasonableness test" that results in clear guidelines and expenditure limits. TXU commented that these guidelines should allow the T&D utility to perform these activities that are of general benefit to the public. PG&E disagreed and questioned whether such a "reasonableness test" would provide clear guidelines and expenditure limits on a T&D utility for economic, education and advertising development, and/or community activities. TNMP stated that one clear bright line is safety. TNMP suggested that other informational activities such as location of buried lines, office hours, and "who to call" information should also be permitted and recoverable. TML commented that it does not support prohibitions or restrictions on the economic development/community support activities of electric utilities. TML suggested that a standard, if needed, should be general in nature, such as a requirement that each utility communicate with all REPs and PGCs on an equal and competitively neutral basis, and be prohibited from operating in a manner that creates an unfair advantage for its affiliate.

Cities commented that education, advertising, and economic development and community support activities are not recoverable from ratepayers unless the activities promote public safety with regard to the transmission and distribution system. OPC stated that regulated utilities should only be allowed to recover from ratepayers the direct expenses incurred in the dissemination of safety information associated with the transmission and distribution system or the provision of transmission and distribution services. Shell commented that if these activities are allowed, the utility should provide contemporaneous notice to its affiliates' competitors and record all activities. In response to OPC and Shell, TXU commented that legislation has recognized the need to protect against anti-competitive behavior and has provided for such protection under SB7, under the Code of Conduct. Further, TXU replied that more customers result in a better more utilized system, which provides more opportunities for REPs. TIEC stated that between September 1, 2000 and January 1, 2002, utilities should be restricted from engaging in education and advertising activities that promote the provision of competitive retail energy and customer services. Furthermore, TIEC commented that after January 1, 2002, utility shareholders should fund any economic development and community support activities and any education and advertising should be restricted to that which is germane to providing wires services (*i.e.*, safety advertising). CU/TLSC/Texas ROSE suggested that the bright line is whether the activity benefits customers of the T&D utility or shareholders. CU/TLSC/Texas ROSE commented that education and advertising by the T&D utility should be limited to providing objective, non-promotional information relating to public education and safety communication programs specific to transmission and distribution. PG&E suggested that, at a minimum, the commission should ensure that such programs are directly related to transmission and distribution, and do not provide a preferential benefit to the utility's affiliates. PG&E commented that with respect to economic development activities, the proposed rules should specify a procedure and standard that a utility must meet prior to engaging in economic development activities.

As with economic development and community support services, the commission concludes that advertising and consumer education activities are not competitive energy services and should not be defined as such under proposed §25.341(6). The commission finds that the standard should be whether an electric utility's activities within economic development, community support, advertising and consumer education promote the provision of a competitive energy service as defined by proposed §25.341(6). Proposed §25.343 prohibits a regulated utility from promoting or providing a competitive energy service and the Code of Conduct applies to assure that economic development, community support, advertising, and customer education offered by the regulated utility do not preferentially benefit the utility's affiliate(s).

The electric utility will file its proposed transmission and distribution rates for the transmission and distribution utility on April 1, 2000. In that filing, any utility seeking cost recovery for economic development, community support, advertising and customer education activities shall provide a listing and description of the activities it has supported in the past using regulated revenues for which it wishes to continue to seek recovery. If any party objects to such cost recovery, the utility shall demonstrate that its contribution to such programs: (1) is at a reasonable level, (2) does not promote the provision of a competitive energy services, particularly one being provided by the utility's affiliate, (3) are conducted in a manner consistent with the code of conduct, and (4) benefit the utility's customers.

Activities intended to attract new business to the community are considered to be such a benefit, since they increase the base over which a utility's costs are shared. If the amounts included are at or below levels previously included in utility rates, they shall be presumed reasonable. For example, a utility's financial contribution to a non-affiliated local economic development council, consistent with historic support levels, would be an appropriate activity to continue.

To facilitate the tracking of economic development and community support activities better in the cost separation filing schedules, the words "economic development programs, community support, advertising, customer education activities," were inserted in §25.341(26) after the words "tariff administration".

Twelfth question:

Should either an electric utility or a transmission and distribution utility be able to provide street lighting after September 1, 2000? If so, should there be any limitation on the provision of such service or specific terms and conditions under which the utility is allowed to provide such service? If an electric utility or a transmission and distribution utility should not be allowed to provide street lighting in total, is there some portion of the service that they should be allowed to provide?

EGSI, Reliant, CSW, SPS, TXU, and Cities commented that the provision of street lighting to municipalities and unincorporated communities should be permitted to continue after September 1, 2000. Furthermore, these parties stated that beginning on January 1, 2002, the energy portion of such service would become competitive. EGSI stated that it is obligated under franchise agreements to provide street lighting after September 1, 2000. In addition, EGSI commented that safety and reliability concerns require that it continue to provide street lighting. CSW commented that street lighting should continue to be offered by the electric utility and T&D utility. In considering whether a T&D utility should continue to provide this service, CSW stated that the commission should also consider non-electric issues, such as community safety. Reliant stated that the Code of Conduct and the commission's rate setting authority should be sufficient to protect the public interest. TNMP commented that the T&D utility should continue to provide street lighting under existing tariffs. TML stated that there should be no restrictions, total or partial, on the authority of a T&D utility to provide street lighting. TML suggested that if street lighting projects by T&D utilities prove, in the future, to provide an unfair advantage to a class of retail competitors, regulatory action may be appropriate at that time.

OAG commented that any service that might be competitive now or in the future should be deemed competitive for unbundling purposes, including street lighting service. OPC commented that street lighting service is a competitive energy service. TESCO/TACCA/IEC commented that contractors could install roadway streetlights; however, utilities have indicated to TESCO/TACCA/IEC that they would not allow access to their poles for reasons of safety and liability. TESCO/TACCA/IEC suggested that the commission inquire further into how other industries (such as the telephone industry) have addressed similar situations. TIEC commented that between September 1, 2000 and January 1, 2002, only those utilities with existing street lighting tariffs should be permitted to provide street lighting services. However, TIEC stated that because street lighting can be a competitive service, all T&D utilities should be restricted from providing these services after January 1, 2002. CU/TLSC/Texas ROSE commented that street lighting should be subject to the same standards as other competitive energy services. PG&E stated that the energy for streetlights should be provided on a competitive basis after the implementation of customer choice. PG&E commented that the facility maintenance component of street lighting is capable of being provided on a competitive basis, and thus is a competitive energy service. Utilities are precluded from providing that service on and after September 1, 2000, if that service is available in its territory, and if not, are barred from providing that service on or after January 1, 2002. In response to commentaries supporting the inclusion of street lighting to the list of competitive energy services, Reliant stated that these services are not competitive because they are not widely available. No entity other than the T&D utility can construct and maintain lighting along roadways. Reliant replied that no limitations should be placed on utilities that continue to provide street lighting, since the commodity sales will soon be competitive after January 1, 2002. OAG commented that it takes no position on operation and maintenance (O&M) of street lighting as "competitive energy services" since the State provides these O&M services to its own street lighting accounts. However, OAG commented that State street lighting accounts which have a peak load less than 1000 kW cannot be forced onto competitive rates as prescribed by the "price to beat" provisions of PURA §39.202(a) and (o).

While certain aspects of street lighting service may properly be considered competitive energy services, the commission finds that a separate rulemaking project should be set up to more closely analyze the issues surrounding the procedures for separating street lighting service from the regulated utility and the potential impacts of separation on affected parties. Based on the comments received, the commission notes that several parties expressed concerns regarding service reliability and community safety with the prohibition of the regulated utility offering street lighting services. The commission recognizes that street lighting serves an important public safety function for motorists and pedestrians along public roadways and highways. In the rulemaking, parties shall explore the extent to which components of roadway street lighting service other than energy may be competitively provided, and the proper role of the T&D utility in ensuring that this vital public necessity is efficiently provided to municipalities. After January 1, 2002, the responsibility to provide roadway street lighting may reside with the REP chosen to be the provider of last resort service or may be competitively bid, depending on the municipal government's or other customer's decision. The rulemaking should be completed on this issue prior to January 1, 2002. As a result, the commission declines at this time to incorporate street lighting service into the definition of competitive energy services.

Thirteenth question:

What advanced metering services and equipment, if any, should be included within the definition of competitive energy services as defined in the proposed rules?

EGSI and TXU commented that no advanced metering services should be declared competitive energy services. EGSI commented that PURA §39.107 precludes the commission from declaring any type of metering services and equipment competitive prior to the dates specified in that section. CSW commented that a definition of advanced metering service and equipment does not need to be included because it is simply any service or equipment above the standard metering service provided by the T&D utility. PG&E stated that the utilities failed to articulate any reason for excluding advanced metering services from the definition of competitive energy services. Furthermore, PG&E replied that utilities have the right and obligation to provide standard metering until standard metering service becomes competitive under PURA §39.107; however, this section of PURA does not apply to advanced metering. Reliant stated that a list of advanced metering activities should be developed in the next two to three years. Reliant also stated that many advanced meters possibly could be sold competitively to end-use customers, as long as customer protection rules are agreed to by all market participants, including the T&D utility. SPS commented that upon the date the metering function becomes competitive, the inclusion of advanced customer metering services and equipment within the definition of competitive energy services should be as broad as possible. SPS further commented that the T&D utility should conduct all meter installations. TNMP stated that it could envision a time in the future when advanced metering services and equipment could be competitive energy services.

Cities stated that all of the services on the customer side of the meter should be regarded as competitive and advanced metering services and equipment that address or relate to services on the customer side of the basic meter should be regarded as competitive. Enron commented that any metering device that is different from the standard meter is a competitive energy service and should be defined as such in the proposed rules. Furthermore, Enron stated that utilities should not be permitted to deploy advanced metering services or equipment beyond current practices. OPC stated that all advanced metering services and equipment placed on the customer's side of the meter should be included within the definition of competitive energy services. TESCO/TACCA/IEC stated that any additional metering installed supplemental to the basic metering service, including special submeters or advanced metering equipment, as well as data logging, communication and information management systems, is already competitive. TIEC commented that metering devices and equipment that exceed standard metering requirements, as defined in proposed §25.341(19), should be classified as advanced metering services and included within the definition of competitive energy services. TIEC recommended that an exception should be made for any advanced metering equipment that has already been installed for a customer by incumbent utilities. PG&E stated that any advanced metering, as that term is defined under proposed §25.341(3), should be included in the definition of competitive energy services. In response to TIEC, OPC, Enron, PG&E, and Cities, EGSI commented that these commentaries conflict with PURA §39.107(a), that, in a new service area, metering services and equipment "*shall continue* to be provided by the T&D utility" (emphasis added). EGSI replied that these arguments should be rejected and that no advanced metering services should be included in the definition of competitive energy services.

The commission concludes that the definition of competitive energy service should include a provision for customer-premise metering equipment and related services that are not necessary for the measurement of electric energy for purposes of rendering monthly electric bills. The commission finds that these types of meters provide meter data not necessary for the rendering of an electric bill; furthermore, the provision of such information is currently defined as a competitive energy service under proposed §25.341(6)(G). The commission disagrees with utilities' broad interpretations of what constitutes metering services under PURA §39.107. PURA §39.107(a) says "On the introduction of customer choice in a service area, metering services for the area shall continue to be provided by the transmission and distribution utility affiliate of the electric utility that was serving the area before the introduction of customer choice." The commission finds that current commission rules properly define the scope of "metering services" as prescribed by PURA §39.107. Substantive Rule §25.121 (a) and (b) of this title (relating to Meter Requirements) state the following:

"(a) Use of meter. All electricity consumed and demanded by an electric customer shall be charged for by meter measurements, except where otherwise provided for by the applicable rate schedule or contract," and

"(b) Installation. Unless otherwise authorized by the commission, each electric utility shall provide and install and shall continue to own and maintain all meters necessary for the measurement of electric energy usage."

The commission finds that commission rules clearly illustrate utility "metering services" to be "meters *necessary* for the measurement of electric energy usage" used to charge electric customers for "electricity consumed and demanded" (emphasis added). The commission believes that PURA §39.107 does not include the provision of *all* metering/advanced metering equipment and related services to be provided by the regulated utility when such metering services address or relate to the provision of information beyond what is necessary for the calculation of a customer's electricity charges. The commission finds that these services are outside the scope of metering services as prescribed by PURA §39.107. The commission believes that "advanced" metering equipment, related services, and the provision of such energy usage information constitute competitive energy services and should be governed by proposed §25.343. The commission adopts subparagraph (V) to be incorporated into proposed §25.341(6) to read as follows: "customer-premise metering equipment and related services other than as required for the measurement of electric energy necessary for the rendering of a monthly electric bill."

PG&E commented that "any advanced metering" should be added as a new subparagraph within the definition of competitive energy services.

The commission concludes that the inclusion of metering equipment as detailed in the commission's above response properly captures the appropriate metering equipment and related services for inclusion into the definition of competitive energy services. The commission also notes that competitive energy services must be separated out of the regulated utility by September 1, 2000. As defined under §25.341(3), the definition of advanced metering refers to activities of the transmission and distribution utility on or after January 1, 2002. In order to avoid unnecessary confusion, the commission adopts a separate provision relating to metering equipment and related services which are to be deemed competitive energy services and therefore rejects PG&E's proposed language.

Enron commented that installed metering as it exists today should establish the level of "standard metering." TIEC recommended that an exception should be made for any advanced metering equipment that has already been installed for a customer by an incumbent utility. TIEC commented that it would be unreasonable, disruptive, and inappropriate to require the removal of such existing equipment. TIEC stated that any existing advanced metering equipment should be exempted from the definition of competitive energy services.

The commission concludes that it is appropriate to exempt existing metering equipment installed by the regulated utility. The commission finds that the exemption shall *only* apply to metering equipment installed, operated, and maintained by the affected utility prior to the effective date of proposed §25.346(g)(1) and (g)(2)(D). The commission does not intend for the exemption to apply to any other competitive energy service as defined by §25.341(6); in particular, subparagraph (G) relating to "*the provision of information relating to customer usage other than as required for the rendering of a monthly electric bill, including electrical pulse service*." The commission adopts new subparagraph §25.346(g)(1)(B) as follows: "Affected utilities may continue to use metering equipment installed, operated, and maintained by the affected utility prior to the effective date of this section, but may not use the information gained from its provision of the meter or metering services as defined in §25.341(6)(G) of this title (relating to

Definitions)." The commission also adopts new subparagraph §25.346(g)(2)(D)(ii) as follows: "Affected utilities may continue to use metering equipment installed, operated, and maintained by the affected utility consistent with the effective date established under paragraph (1)(B) of this subsection, but may not use the information gained from its provision of the meter or metering services as defined in §25.341(6)(G) of this title (relating to Definitions)."

CU/TLSC/Texas ROSE stated that in a competitive retail market, residential consumers should be capable of switching their REP without paying for a special meter since they are already paying for standard meters in their T&D rates.

The commission believes that the comment provided by CU/TLSC/Texas ROSE is beyond the scope of this rulemaking; however, the commission believes that the issue should be addressed within a future commission rulemaking.

PG&E commented that the definition of advanced metering under proposed §25.341(3) be modified for clarity. PG&E recommended that the definition be reworded: "Includes any metering equipment or services that are not transmission and distribution utility metering as defined in paragraph (26) of this section."

The commission agrees with PG&E's proposed change and modifies the proposed rule accordingly.

§25.341. Definitions.

Comments on the definition of "competition transition charge (CTC)"

CSW commented that the definition of "competition transition charge" should be expanded to include generation-related regulatory assets. CSW provided additional language for this subparagraph.

The commission agrees with CSW and the definition of CTC has been revised to include the transition charges established pursuant to PURA §39.302(7).

Comments on the definition of "competitive energy services"

EGSI, CSW, TXU, and Reliant commented that the proposed definition inappropriately broadens the required separation to "customer energy services business activities which *are capable of being provided on a competitive basis* in the retail market" (emphasis added). These parties commented that this definition is inconsistent with PURA §39.051(a), which requires the separation of only those customer energy services business activities which are "already widely available in the competitive market" by September 1, 2000. These parties recommended that the definition of competitive energy services be defined as services that are already widely available in the competitive market. TNMP commented that prohibiting the T&D utility from offering competitive energy services will prevent access to these services by customers and deny the T&D utility access to information needed for reliability and safety concerns. TNMP recommended that the T&D utility be given more latitude in providing competitive energy services as long as customers have the opportunity to make informed choices regarding the provider of those services.

In response to the utilities, OPC recommended that the commission reject all of the utilities' suggested changes. In particular, OPC commented that EGSI, TXU, Reliant, and CSW's proposed changes weaken the rule in that such changes would allow a regulated entity entry into competitive energy markets, where it could subsidize such activities using captive ratepayer funds. In response to parties' comments that claim the definition of competitive energy services is overly broad, PG&E stated that the current definition meets the statutory mandate by encouraging the development of the competitive energy services market, and by allowing the utilities to petition the commission to supply energy services not widely available in the market during the transition.

The commission disagrees that the definition of competitive energy services goes beyond the statutory requirement for separation of competitive energy services. The commission notes that the definition of competitive energy services is not the rule which enacts PURA §39.051(a). The definition of competitive energy services coupled with proposed §25.343 does implement PURA §39.051(a). PURA §39.051(a) mandates that widely available customer energy services business activities be separated from the regulated utility no later than September 1, 2000. The commission finds that the widely available standard is implemented through the petition system as prescribed in proposed §25.343(d)(1). The commission finds that this mechanism provides the utility the opportunity to petition the commission to provide a competitive energy service which is not widely available within a given area. The commission finds that proposed §25.343

and the definition of competitive energy services properly implement PURA §39.051(a), protect customers from being denied competitive energy services due to the lack of competitive providers within an area, and advance the growth of a robust retail energy services market in Texas.

TESCO/TACCA/IEC commented that the definition of competitive energy services should be amended to clarify that competitive energy services do not include activities necessary to the utility's administration of approved energy efficiency programs. TESCO/TACCA/IEC proposed additional language for incorporation into §25.341(6). EGSI concurred with the proposed changes.

The commission agrees with TECSO/TACCA/IEC and modifies §25.343 (c) to state: "except for the administration of energy efficiency programs as specifically provided elsewhere in this chapter." The commission finds that this modification clarifies that the utility may engage in specific commission-approved activities relating to the administration of energy efficiency programs addressed under proposed §25.181 (relating to Energy Efficiency Programs).

PG&E commented that the definition of competitive energy services should establish a rebuttable presumption that all non-system services are competitive energy services and, during the transition period, widely available. In response, EGSI stated that PG&E's presumption goes far beyond what the statute permits and conceivably could prevent services from reaching customers. TXU commented that PG&E's proposal should be rejected because it would deny a customer a needed service solely on the claim that a non-affiliated REP will provide the service at some future time. OPC commented that it supports the definition of competitive energy services.

The commission disagrees with PG&E's proposed rebuttable presumption that all non-system services are competitive energy services and during the transition period, widely available. The commission finds that the petition system must be flexible in order to review petitions on a case-by-case basis. The commission declines to make any presumption that would limit its ability and other affected parties' ability to adequately review a petition.

Reliant commented that the definition of competitive energy services should not preclude an electric utility or a T&D utility from providing competitive energy services to itself. Reliant proposed additional language for this subsection. In oral comments, Reliant clarified that, for example, the T&D utility should not be precluded from working, building, or constructing its own substations.

The commission declines to incorporate Reliant's proposed changes. The commission finds that Reliant's comments refer to transmission and distribution services that are not competitive energy services and will continue to be performed by the regulated utility providing regulated electric services to end-use customers.

Comments on paragraph (6)(B) "the provision of technical assistance…"

CSW commented that this definition should not preclude a T&D utility from taking necessary actions to comply with the energy efficiency goals imposed by SB7. CSW proposed additional language for this subparagraph. In response, PG&E commented that this section does not prevent the T&D utility from administering energy saving incentive programs. PG&E replied that CSW's revisions are unnecessary, and the energy efficiency rule currently being developed will provide the guidance necessary for utilities to meet their energy efficiency goals.

The commission declines to adopt CSW's proposed changes. Proposed §25.181 (relating to Energy Efficiency) will detail acceptable activities that the T&D utility may conduct to administer energy savings incentive programs in a market-neutral, nondiscriminatory manner.

Nucor commented that this provision should be clarified to exclude utilities' tariffed interruptible and other non-firm rates from the definition of competitive energy services. Nucor provided additional language for this subparagraph.

The commission finds that Nucor's proposed changes are unnecessary. The utilities' tariffed interruptible and other non-firm rates are subject to the rate freeze as prescribed by PURA §39.052, and consequently, the utility is required to continue to provide these tariffed services through December 31, 2001.

Comments on paragraph (6)(D), "customer or facility specific energy efficiency…services")

CSW stated that the T&D utility should retain its ability to provide power diagnostics services to customers, as well as other services necessary to meet service quality, safety requirements and standards, and energy efficiency goals. CSW provided additional language for this subparagraph.

The commission rejects CSW's proposed changes. These services are competitive energy services and the regulated utility may not provide these services unless they successfully petition the commission to provide the competitive energy services under proposed §25.343(d)(1). Furthermore, proposed §25.181 (relating to Energy Efficiency) will detail acceptable activities that the T&D utility may conduct to administer energy savings incentive programs in a market-neutral, nondiscriminatory manner.

Comments on paragraph (6)(E), "the provision of anything of value…"

CSW, TXU, and Reliant stated that the language "anything of value" is too broad. CSW commented that this provision should not prohibit the T&D utility from providing technical consultation and safety information. CSW proposed additional rule language to address the responsibility of the T&D utility to provide funding to energy service providers, customers, and other energy efficiency project developers to meet energy efficiency goals. PG&E replied to CSW, stating that incentives, procedures, and structures for energy efficiency programs will be defined in Project Number 21074, and this provision is crafted to achieve the limited goal of defining competitive energy services. PG&E recommended that the language be left intact.

TXU commented this subparagraph, as proposed, could prohibit even the most innocuous behavior, such as a utility employee serving as the president of a local engineering society. TXU recommended that the following language be added at the end of the subparagraph "for the purpose of influencing their decisions related to the selection of a retail electric provider or energy-consuming equipment or buildings." In response to TXU, PG&E commented that TXU's proposed language would narrow the standard, because it would be virtually impossible to prove that a T&D utility's actions were "for the purpose of influencing" such decisions. PG&E commented that the provision was intentionally drafted to be broad and recommended the commission reject TXU's proposed change.

Reliant commented that this paragraph should not preclude the T&D utility from working with customers to properly size the utility's electric service facilities and interconnection issues relating to the T&D system. Reliant recommended that the phrase "tariffed services" be replaced with "transmission and distribution utility customer services and similar services." In response to Reliant, PG&E stated that the rule narrowly tailors the interactions with the particular customers listed precisely to keep such interactions limited to tariffed services.

The commission agrees with PG&E and declines to make any changes to this subparagraph. The commission finds that it is reasonable to exclude a utility from providing anything of value other than tariffed services to *persons involved in making decisions relating to investments in energy-consuming equipment or buildings on behalf of the ultimate retail electricity customer*. The commission finds this standard to be meaningful and in the public interest.

Comments on paragraph (6)(F), "customer-premises…equipment and related services"

As discussed in Preamble Question Number 8, TXU commented that T&D utilities should be allowed to provide, under tariff, certain reliability-related services that are not widely-available. TXU recommended that this subparagraph exclude "transmission and distribution emergency restoration services and transmission substation inspection and preventive maintenance services that impact transmission reliability" from customer-premises transformation equipment. PG&E replied that the first part of TXU's proposed new provision "other than transmission and distribution emergency restoration" is appropriate, provided that the service is petitioned to the commission, is reported when emergency restoration service occurs, and is limited to those actions necessary to ensure grid reliability. However, PG&E stated that the latter part of TXU's proposal is inappropriate because such services can be supplied by the competitive market.

The commission rejects TXU's proposed changes. The petition procedure of §25.343(d)(1) should allow TXU to provide these services if justified.

Comments on paragraph (6)(G), "the provision of information relating to customer usage…"

As discussed in Preamble Question Number 13, TXU recommended deletion of this section until metering becomes competitive. In the alternative, TXU recommended that the phrase "including electrical pulse service" be deleted from this provision. TXU commented that electrical pulse service is not sold as a broader energy management service or in conjunction with energy management hardware or software and should continue to be offered through the utility as long as metering remains a regulated service. TNMP commented that the utility currently provides electrical pulse service at the customer's request. TNMP stated that if the utility cannot provide the service, there could be problems with meter accuracy verifications and testing if meter ownership and theft protection is not maintained by the utility.

As discussed under Preamble Question Number 13, the commission finds that the provision of information provided through electrical pulse service, other than the information needed to render an end-use customer's electric bill, is a competitive energy service, and declines to make TXU or TNMP's proposed changes.

In reply comments, CSW requested clarification of what specific energy services are contemplated by this provision. In particular, CSW asked whether this energy service would include written information that may be requested by the customer, such as demand-side management and energy efficiency information or include information related to electric technologies provided to a customer upon request.

The commission finds that the regulated utility may provide only such information necessary for the provision of regulated electric services to end-use customers. Activities which are beyond the scope of the utility's provision of regulated electric services are competitive energy services and prohibited. It would be appropriate for a utility to refer a requestor to a list of REPs or other providers serving in an area consistent with §25.272(h)(4) of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates).

Comments on paragraph (6)(H), "communications services…"

CSW requested clarification of what specific energy services are contemplated by this provision. In particular, CSW asked whether "communication services" would include verbal or written communication provided to a customer relating to energy usage, such as that provided upon completion of an energy audit or include verbal communication for a high bill complaint or request for assistance.

The commission finds that "communication services" permitted to be offered by utilities are limited to services necessary for the provision of regulated electric service to end-use customers. Activities which are beyond the scope of the utility's provision of regulated electric services are competitive energy services and are prohibited.

Comments on paragraph (6)(J), "non-roadway, outdoor security lighting"

CSW commented that if a utility must cease to provide "non-roadway, outdoor security lighting" on September 1, 2000, investments in facilities could be lost and customers may be denied services. CSW noted that these rates are tariffed services and subject to the rate freeze and recommended that the commission restrict the availability of these services to existing customers until January 1, 2002. CSW stated that for new services after January 1, 2002, the T&D utility would provide distribution facilities (poles and connection to secondary), but the end-use equipment (fixtures, bulbs, etc.), energy consumed by the facility, and the maintenance, repair, and replacement of end-use equipment would be competitive services not offered by the T&D

utility. TXU commented that security lighting is a competitive energy service; however, it is not practical or economically sensible to prohibit utilities from serving existing locations. TXU commented that its thousands of security lights would have to be modified to alleviate conflicts between National Electric Safety Code (NESC) standards (under which only utilities are allowed to operate) and the National Electric Code (NEC) standards. Furthermore, TXU stated that the Texas Health and Safety Code prohibits work by non-utility personnel within six feet of energized (over 600 volts) power lines. TXU commented that many security lights are connected directly to the TXU system, which operates at up to 21,000 volts. TXU recommended that the rule be revised to allow utilities to close existing tariffs to new customers and continue to provide service to existing customers under those tariffs until the start of retail competition. TXU commented that after the start of competition, T&D utilities would have a tariff solely for the provision of lights existing on the closing day of the tariff.

The commission finds that the provision of non-roadway, outdoor security lighting services (such as end-use equipment (poles, fixtures, and bulbs), and the operation, maintenance, and replacement of such end-use equipment) are competitive energy services. Pursuant to PURA §39.051(a), the commission concludes that these services should be separated from the regulated utility no later than September 1, 2000. However, the commission also finds that the provision of existing tariffed non-roadway, outdoor security lighting service is subject to the retail base rate freeze as prescribed by PURA §39.052. In order to reconcile the required separation with the rate freeze, the regulated utility should close its existing non-roadway, outdoor security lighting tariffs to new customers on and after September 1, 2000 but continue to provide these services to existing customers during the freeze period. Following the freeze period, such services should be transferred to the affiliated REP or other affiliates. A change has been made to §25.341(6)(J) to reflect this provision of service to existing customers. With regard to TXU's comments concerning the Health and Safety codes, the commission believes that the problem is resolved during the freeze period by allowing the utility to continue to serve its existing customers. The commission anticipates that new customers can be served by competitive providers without violating the Health and Safety codes since the utility will provide the necessary services or transformers as distribution services. Prior to the expiration of the freeze period, the commission will revisit the potential conflict between the safety codes for existing security lighting customers.

Comments on paragraph (6)(N), "retail marketing…"

TXU commented that utilities should be allowed to continue to provide retail marketing, selling, demonstration, and merchant activities related to services it can and must sell to customers through December 31, 2001. TXU commented that this subsection could prevent a utility from sending information to a customer about reading an electric meter or energy conservation. PG&E replied that if TXU is contemplating sending energy saving information outside an energy efficiency program, such service is capable of, and currently is, being provided on a competitive basis. PG&E recommended that the definition remain intact.

The commission agrees with PG&E and declines to make any changes to this subparagraph. The commission finds that this paragraph is not intended to preclude activities that are necessary for the provision of regulated electric service to end-use customers. The commission is particularly concerned that existing utilities do not use the period immediately prior to the introduction of customer choice to engage in marketing-type activities which create a linkage in the customer's mind between its power delivery function and its soon-to-be deregulated merchant function. The commission finds that the regulated utility is prohibited from engaging in retail marketing, selling, demonstration, and merchant activities which are beyond the provision of regulated electric services.

Comments paragraph (6)(V) "customer education…"

PG&E suggested that the qualifier "that do not benefit the utility's affiliates" be deleted. PG&E commented that because the activities being described are included within the definition of competitive energy services, this activity cannot be engaged in by T&D utilities except under limited circumstances. As discussed under Preamble Question Number 11, EGSI recommended that this subparagraph should be deleted from the definition. CSW recommended adding an exception to this subparagraph which allows the utility to engage in customer education activities when pertinent to the promotion of energy efficiency goals. TXU commented that customer education should not be treated as a competitive energy service and recommended its deletion. In the alternative, TXU commented that only those customer education activities that promote services provided by competitive affiliates of the utility should be restricted; therefore, "market neutral" consumer education programs should continue. In response to TXU's comments, Shell stated that the commission should "strongly suspect" whether utilities can provide "market neutral" customer education. Reliant suggested that these activities must satisfy the Code of Conduct; therefore, the phrases "commission-approved" and "that does not benefit the utility's affiliate(s)" are unnecessary and would create a labor-intensive burden of reviewing and approving of customer education activities. In response to Reliant's recommendation, Shell stated that the commission should closely monitor these activities, if allowed, and approve those activities at the outset. Enron replied to Reliant's proposed changes by stating that the commission should retain broad authority to ensure that a utility's actions conform to the Code of Conduct.

Comments on paragraph (6)(W), "advertising…"

PG&E suggested that the qualifier "that do not benefit the utility's affiliates" be deleted for the reason described in their comments under (6)(V). As discussed under Preamble Question Number 11, EGSI recommended that this subparagraph should be deleted from the definition. CSW recommended adding an exception to this subparagraph which allows the utility to engage in advertising activities when pertinent to the promotion of energy efficiency goals. In response, PG&E stated that Project Number 21074 *(Energy Efficiency Programs),* the commission's energy efficiency rulemaking, is the appropriate place to address the specific energy efficiency activities to be performed by the utility. TXU commented that this subparagraph is inappropriate because utilities should be able to conduct advertising related to the services it can and must sell to customers after September 1, 2000. TXU recommended that the code of conduct and the commission's authority to prohibit the recovery of unreasonable advertising expenses should be sufficient to address any concerns. In response to TXU, PG&E commented that it is "difficult to fathom" what advertising a monopoly utility must engage in other than safety advertising, which the proposed rule permits. PG&E recommended rejecting proposed deletion because it risks preferential treatment and cross-subsidization to the competitive affiliate during and after the transition period. As discussed under definition (6)(V), Reliant recommended the phrases "commission-approved" and "that does not benefit the utility's affiliate(s)" be deleted. As discussed under definition (6)(V), Shell replied that the commission should closely monitor these activities, if allowed and approve those activities on the outset. As discussed under definition (6)(V), Enron replied that it disagreed with Reliant's proposed changes.

Comments on paragraph (6)(X), "economic development and community affairs…"

PG&E suggested that the qualifier "that do not benefit the utility's affiliates" be deleted for the reason described in their comments under (6)(V). Shell commented that T&D utilities should not be allowed to conduct or to recover any economic development and community affairs' expenses, even those specific to transmission and distribution. Shell recommended the deletion of the exception in this subparagraph. As discussed under Preamble Question 10, EGSI commented that this subparagraph should be deleted from the definition. CSW recommended that the T&D utility continue to provide economic development and community service activities as a part of its overall costs. TXU recommended deletion of this section and Reliant recommended the phrases "commission-approved" and "that does not benefit the utility's affiliate(s)" be deleted. Shell replied that the commission should closely monitor these activities, if allowed, and approve those activities on the outset. Enron disagreed with Reliant's proposed changes.

As discussed in Preamble Question Numbers 10 and 11, the commission finds that customer education, advertising activities, and economic development and community support activities are not competitive energy services per se and has deleted references to such services from this subsection. To the extent such activities are within the scope of the regulated utility's function, the activities may be appropriate activities. The commission will approve cost recovery for only those types of services that are deemed to be within the scope of the regulated utility's function consistent with the guidelines in Preamble Question Numbers 10 and 11.

Comments on paragraph (6)(Y), "other activities identified by the commission"

EGSI, TXU, and Reliant commented that the petitioning system establishes a process for reclassification of services as competitive energy services; therefore, this provision is unnecessary and should be deleted.

The commission disagrees with the parties' comments and declines to make any changes to this subparagraph.

Comments on the definition of "discretionary service"

PG&E proposed additional language that clarifies that a discretionary service is not a competitive energy service and does not preferentially benefit the utility's affiliate.

The commission agrees with PG&E. The commission believes that the clarification should be addressed within proposed §25.342(f)(B)(ii) and amends the subparagraph by adding "on a nondiscriminatory basis" after the word "utility." The commission also adopts the following clause (v): "A discretionary service is not a competitive energy service as defined by §25.341(6) of this title (relating to Definitions)."

Comments on the definition of "distribution"

EGSI commented that the definition of distribution should be modified to clarify that the FERC will determine the delineation between transmission and distribution facilities for non-ERCOT utilities. EGSI proposed the following language to be inserted after 60 kilovolts, "or other facilities determined by the FERC to be distribution." CSW recommended that the commission evaluate and consider the FERC's "seven factors test" in drawing the line between transmission and distribution and be able to defend its definition of distribution.

The commission recognizes that the distinction between transmission and distribution in non-ERCOT areas of the State raises questions of Federal preemption and the commission will properly defer to Federal jurisdiction there. However, the commission does not believe that any modification of this proposal is necessary at this time.

Comments on the definition of "generation"

TIEC stated that this definition for the generation function should be expanded to be consistent with the statutory definition of generation assets in PURA §39.251(3) and the definition of generation assets in §25.341(13) of the proposed rule. TIEC stated that these definitions include items such as land and water rights that may not be adequately captured in the definition of generation contained in §25.341(12) of the proposed rule. TIEC further commented that this modification has the advantage of ensuring consistency in the definition of generation function for both cost functionalization and ECOM calculation purposes.

The commission determines that there is no need to make the changes suggested by TIEC. The language in proposed §25.341(12) refers to the generation assets including the land and water rights, which are defined in proposed §25.341(13).

Comments on the definition of "power generation company"

TIEC stated that the definition of power generation company, taken verbatim from the statute, refers to a "facility otherwise excluded from the definition of 'electric utility' under this section…." TIEC stated that electric utility is not defined in the proposed rules; therefore, the subparagraph (B) should be amended to refer to the definition of an electric utility under PURA §31.002(6).

The commission agrees with TIEC and has adopted its proposed language.

Comments on the definition of "standard meter"

Reliant commented that the definition of standard meter should include any meter that a T&D utility has in service or in inventory as of December 31, 2001. EGSI replied that it supports adoption of Reliant's proposed change. OPC responded to Reliant by stating that it sees no reason why the definition of a standard meter should include meters in inventory.

The commission declines to incorporate Reliant's proposed language. The commission finds that Reliant's comments inappropriately expand the definition of the "standard meter" to include all meters (whether standard or advanced) in service and in inventory as of December 31, 2001 which would render the definition of the "standard meter" meaningless.

Comments on the definition of "system service"

Nucor commented that all ancillary services must be provided by the T&D utility as a backstop to any provision of such services by the competitive market. In response to Nucor's comments, EGSI stated that if the commission adopts Nucor's recommendation, then the commission should also make it clear that the costs of providing ancillary services are recoverable. TXU replied to Nucor's comments by stating that SB7 prohibits a T&D utility from selling or buying electricity except for its own use; thus, the T&D utility is prohibited from providing all necessary ancillary services.

The commission agrees with TXU's comments and declines to incorporate Nucor's proposed changes into the paragraph.

EGSI stated that the definition of system services should clearly differentiate between metering for end-use customer billing and metering used by T&D utilities to plan and operate the T&D networks.

The commission concludes that no changes are necessary to differ between end-use customer metering and metering used by the T&D utilities to plan and operate the T&D networks. The commission finds that §25.341(21)(B) as proposed sufficiently addresses the planning and operation functions of the transmission and distribution system. To the extent that metering is used for T&D network planning and operation, the commission finds that this subparagraph is broad enough to capture this function.

CU/TLSC/Texas ROSE commented that administrative support for existing energy aid programs (*i.e.*, Energy Aid, Project Care, and Project Share) should be classified as an appropriate T&D utility programs derives from customer contributions, utilities provide administrative support to ensure that funds reach eligible households that are usually screened by non-profit service providers. CU/TLSC/Texas ROSE recommended that the proposed rule place the responsibility and support for these programs within the T&D utility.

The commission declines to incorporate the administration of these programs into system services at this time. The commission finds that this issue would be better addressed within the cost separation proceedings for inclusion into the T&D utility system service rates.

Comments on paragraph (21)(D), "response to electric delivery problems…"

CSW recommended that the T&D utility should retain some responsibility for maintaining the quality of the power delivered to end-use customers. CSW proposed to include "power quality monitoring and diagnostics" as part of the T&D utility's system service function. In response, PG&E commented that §25.341(21)(A), which allows a utility to regulate and control electricity in the transmission and distribution system, would encompass power quality monitoring and diagnostics for the transmission and distribution system. However, PG&E commented that power quality monitoring and diagnostics services for the end-use customer with respect to facilities installed by the competitive provider for the benefit of a specific customer are clearly competitive energy services. PG&E recommended rejection of CSW's proposed changes.

The commission agrees with PG&E and rejects the changes suggested by CSW.

Comments on paragraph (21)(E), "commission-approved public education programs…"

PG&E commented that this subparagraph should contain a qualifier which states that commission-approved public education and safety communication programs offered by the T&D utility cannot preferentially benefit the utility's affiliate(s). PG&E proposed language for this subparagraph.

The commission agrees with PG&E's comments. The commission finds that limited consumer education activities that are specific to transmission and distribution, not preferentially beneficial to the utility's affiliate(s), and do not promote the provision of a competitive energy service are reasonable activities for which the T&D utility may seek cost recovery during a rate proceeding before the commission. The commission amends subparagraph (E) as follows: "commission-approved public education and safety communication activities specific to transmission and distribution that do not preferentially benefit the utility's affiliate(s)."

As discussed under definition (6)(V), Reliant commented that the phrase "commission-approved" should be deleted. Reliant also recommended the addition of economic development and community affairs programs to this subparagraph. Reliant proposed a new subparagraph (E) which adds "customer care and call center activities related to, among other things, responding to electric delivery problems" as an example of a system service. EGSI recommended that the rule explicitly include economic development activities, community affairs activities, customer care activities, and customer call center activities in the definition of system services. OPC commented that while it is not opposed to the changes suggested by Reliant which relate to proposed additions (E) and (F), these additions are not services that are essential as prescribed by the definition of system services. Shell replied to EGSI and Reliant's comments stating that the only call-handling capabilities the T&D utility needs is to field REP inquiries and for notification of emergencies; therefore, the call center should move to the affiliate REP.

The commission declines to incorporate the additional examples of services within the definition of system services as proposed by Reliant and EGSI. The commission finds that the language provided by EGSI and Reliant is overly broad. As previously discussed in Preamble Question Numbers 10 and 11, the commission finds that limited economic development and community support activities that are specific to transmission and distribution function, not preferentially beneficial to the utility's affiliate(s), and do not promote the provision of a competitive energy service may be reasonable activities for which the T&D utility may seek cost recovery during a rate proceeding before the commission.

As also discussed under Preamble Question Number 6, the commission believes the T&D utility should have limited interface with the end-use customer, and the utility's customer service function (*i.e.,* customer care and call center activities) should be focused toward the retail electric provider rather than the retail electric provider's end-use customer. The commission is committed to reviewing all activities and associated costs proposed by the T&D utility for cost recovery under the aforementioned standard and only considering prudent activities and associated costs within the scope of the T&D utility's function for inclusion within the utility's regulated rates.

Comments paragraph (21)(G), "…incentives for energy efficiency programs"

CSW stated that this paragraph should be changed to read as follows: "commission-approved administration of energy savings incentive programs in a market-neutral, nondiscriminatory manner, through standard offer programs or limited, targeted market transformation programs." OPC responded that it supports CSW's proposed change. As discussed under definition (6)(V), Reliant commented that the phrase "commission-approved" should be deleted.

The commission agrees with CSW and has adopted its proposed language. The commission disagrees with Reliant's proposed change. The commission's review of utility activities pertaining to the administration of market transformation programs and energy efficiency programs shall occur under proposed §25.181 (relating to Energy Efficiency). Finally, the commission finds the word "specific" to be unnecessary and has deleted it from the proposed subparagraph.

Comments on the definition of "transmission and distribution utility"

As addressed by TIEC in its comments on proposed §25.341(15), TIEC stated that electric utility is not defined in the proposed rules; therefore, subparagraph (B) should be amended to refer to the definition of an electric utility under PURA §31.002 (6).

The commission agrees with TIEC and has adopted its proposed language.

Comments on the definition of "transmission and distribution utility billing system services"

Shell suggested that the commission allow the T&D utility to include in its billing system services the ability to recover uncollectible debts. Shell also commented that if the T&D utility maintains a customer call center, the center should be provided for the exclusive use of those REPs which elect for the T&D utility to provide commission-approved tariffed billing services.

The commission finds that the retail electric provider is responsible for retail customer uncollectibles and declines to incorporate Shell's comments into the definition.

Comments on the definition of "transmission and distribution utility metering system services"

As discussed under paragraph (6)(G) regarding the definition of "competitive energy services", TXU commented that electrical pulse service should be included within the definition of transmission and distribution utility metering system services.

The commission finds electrical pulse service to be a competitive energy service, and therefore declines to include it in the definition of transmission and distribution utility metering system services.

Reliant commented that T&D utility metering system services should recognize that the T&D utility will be required to send metering information to other parties through electronic data interchange as part of the settlement process. Reliant proposed an additional paragraph for this comment.

The commission concludes that the change proposed by Reliant is adequately addressed by §25.346(i)(3) of the proposed rules.

TNMP commented that this definition contains services (for example, re-reads, meter testing, etc.) for which a tariff for additional charges currently exists and should continue in some form. TNMP commented that these services will not be rate-based costs.

The commission agrees with TNMP that these services are examples of regulated services that support the provision of system services and should be classified as discretionary services as prescribed by proposed §25.342 (f)(1)(B).

Comments on paragraph (26)(G)

TNMP commented that "theft detection and prevention" should be clarified to account for differences among utilities' programs. TNMP proposed to add the word "current" in front of theft in order to clarify that the REP will be responsible for additional programs above and beyond what the utility currently does.

The commission declines to amend this subparagraph. The commission finds that TNMP's proposed changes are unnecessary and do not clarify the subparagraph. The commission believes that this provision appropriately designates responsibility for meter theft prevention and detection to the transmission and distribution utility.

Commenters proposed additional definitions

PG&E suggested that its changes to proposed §25.342 necessitate adding a definition for the "transition period" as the period from September 1, 2000 through December 31, 2001.

The commission concludes that this definition is not necessary and declines to incorporate the proposed definition into this section.

Enron proposed a definition of "book value" as it relates to both business separation and functional cost separation rules.

The commission disagrees with Enron and determines that there is no need to define book value in this section.

Enron proposed a definition of "embedded cost" and commented that this definition should be included as it relates to both business separation and functional cost separation rules.

The commission disagrees with Enron and determines that there is no need to define embedded cost in this section.

Enron proposed an additional definition for "non-bypassable wires charge" due its being referenced numerous times within proposed rule §25.344 and §25.345.

The commission disagrees with Enron and determines that there is no need to define non-bypassable wires charge in the section.

§25.342. Electric Business Separation.

Enron commented that the January 10, 2000 filings should be litigated cases to afford all parties the opportunity to review, evaluate, and challenge the utility filings. OxyChem stated that it generally supports comments provided by TIEC.

The commission notes that PURA §39.003 requires that each commission proceeding other than a rulemaking, report, notification or registration be conducted as a contested case and the burden of proof be on the incumbent electric utility. Therefore, there is no need to reiterate such a requirement in this rule.

Enron further commented that to properly evaluate the plan under a "reasonableness" test, a best estimate of the value of the assets and liabilities is necessary. Enron argued that the plan should include the book values of any asset or liability that may be transferred. Reliant objected to Enron's suggestion to include the cost data in the Business Separation Plan Filing Package (BSP-FP). According to Reliant, it is not necessary to have cost data to determine if the plan complies with PURA §39.051. Reliant stated that the unbundled cost of service proceeding is the appropriate forum for determining whether the costs assigned to the regulated T&D utility under the business separation plan are reasonable.

The commission agrees with Reliant and finds that it is not necessary to mandate that the business separation plans include book or market value of the assets. There will be ample opportunity for the commission and interested parties to review the value of assets during the cost separation proceedings. The focus of such proceedings will be which assets and costs will be included in the T&D utility system rates, not on assets and costs left outside such rates. Nevertheless, should any such information be required to evaluate the business separation plan, parties may request data under existing commission procedures. The commission reserves the right to approve portions of the business separation plan.

TNMP requested that the commission add a special circumstance waiver section under which the utility may request that T&D utility employees be allowed to perform REP duties in small local offices for the convenience of customers. TNMP contends that the waiver could be structured so as not to violate the intent of SB7 and would allow TNMP to operate its T&D utility in a similar manner in both Texas and New Mexico. In reply comments, Shell argued that the commission should reject TNMP's request because SB7 provides no exception for rural offices and rural customers are equally entitled to the benefits of competition.

The commission disagrees with TNMP and declines to make the proposed changes. An affected utility can explain its unique circumstances in its business separation plan filing and can petition for a waiver as allowed in proposed §25.343 and Section L of the BSP-FP.

Subsection (d) Business separation

TXU and CSW commented that subsection (d)(1) of the proposed rule goes beyond the separation requirement in PURA §39.051 (requiring a utility to separate from its regulated utility activities its customer energy services business activities that are otherwise also already widely available). TXU referred to its position presented in Preamble Question Number 7. In reply, Shell disagreed with TXU and contended that only by separating competitive services into a separate company can the utility separate competitive energy services from regulated utility services. CSW further argued that to prevent a utility from providing these services would violate the rate freeze provisions of SB7 to the extent that such services are tariffed. CSW stated that a requirement that a utility cease offering a tariffed service and shift a tariffed service to an entity that does not yet exist (the REP), that is not a regulated utility, and that is not bound to frozen tariff rates, is contrary to the rate freeze. CSW argued that the rule should allow the utility to offer the services on a basis separate from its regulated activities rather than prohibiting the utility from providing those services during the transition period. In reply comments, OPC disagreed with CSW's assertion that subsection (d)(1) conflicts with PURA. OPC stated that the regulated utility might no longer provide these services; however, an unregulated affiliate may provide widely available energy services.

The commission disagrees with TXU and CSW and finds that the definition of competitive energy services, in conjunction with the petition system proposed in §25.343, allows utilities enough flexibility to offer services that are not widely available in the market. With regard to the comments stating that separation does not require that the activities be severed into a separate corporation, the commission will reserve judgment on this legal and policy issue until it reviews the business separation filing of the individual company.

OPC, Shell, and Cities argued that the transfer of assets under subsection (d)(4) during unbundling should not be transferred at book value but at higher of the book or market. EGSI, TXU, Reliant, and CSW supported valuation at book value and objected in reply comments to the other valuation methods proposed.

The commission notes that this issue has already been debated and affirms its previous ruling that the assets transferred during the initial unbundling shall be based on book value.

TIEC recommended a modification to subsection (d)(4) to clarify that although transfers should occur at book value, such transfers should not be performed in a manner that disadvantages the T&D utility or its customers. TXU objected to TIEC's suggestion because such language would invite arguments about what "disadvantages" a T&D utility customer. TXU argued that imposing such a broad level of subjectivity on each transfer would be unnecessarily burdensome and a more straightforward approach would be appropriate.

The commission finds that there are sufficient safeguards in §25.272, *Code of Conduct for Electric Utilities and Their Affiliates,* and these rules for the commission and interested parties to review the reasonableness of the asset transfers and declines to make the changes suggested by TIEC.

Subsection (e) Business separation plans

TIEC recommended modifying the reference to competitive energy services provided by T&D utilities in subsection (e)(1)(E). TIEC stated that T&D utilities should only be permitted to provide retail energy services if they could demonstrate that these services are not competitively available in their service territories, and thus, would be considered non-competitive services.

The commission agrees with the comments of TIEC. The commission concludes that references to competitive energy services should be deleted from this subparagraph. Under subsection (e)(1)(D), the affected utility is mandated to provide information as set forth in proposed §25.343 including the utility's proposed petitions to provide competitive energy services, if any. The commission finds that petitions pursuant to proposed §25.343 will provide sufficient description of "petitioned services" that may be provided by the T&D utility.

Shell suggested an addition to subsection (e)(1) that would require each utility to state whether it has included each of the services in a tariff on file with the commission. Such a requirement would improve administrative efficiency in the compliance process. Shell commented that the commission should require a T&D utility's tariff to describe all services that the utility offers and the statement should be made as part of the code of conduct compliance.

The commission declines to make Shell's proposed changes because they are unnecessary. The proposed rules require that any service offered by a T&D utility be provided under a commission-approved tariff. The commission notes that the utility must provide tariffs for the competitive energy services it is petitioning to provide after September 1, 2000 as part of the information required in Section L of the BSP-FP. Tariffs for the system, discretionary and other services will be evaluated in the cost separation proceedings.

CSW commented that the schedule for supplemental filings required by subsection (e)(2) should be more flexible to recognize the varying circumstances facing several utilities in Texas.

The commission determines that there is enough flexibility to address CSW's concerns in the rule and BSP-FP and declines to make the suggested changes to the rule.

Given the comments received regarding the confidentiality under proposed §25.345(f), the commission deletes §25.342(e)(3). The commission believes that given the comments, the issue of confidentiality is best addressed through the use of a protective order. The commission is developing a standard protective order in Project Number 21662, *Development of a Standard Protective Order for Use in SB7 Transition Cases*.

Subsection (f) Separation of transmission and distribution utility services

CU/TLSC/Texas ROSE indicated their support for the pricing of discretionary services set forth in subsection (f)(1)(B), requiring that the pricing of any service offered by the T&D utility be provided on a non-discriminatory, embedded cost-based tariff to any eligible customer. CU/TLSC/Texas ROSE stated that the tariff should explicitly state the specific dollar amount to be charged to the customer in order to provide for a transparent price and to ensure that the tariff is offered on a non-discriminatory basis.

EGSI requested that the pricing requirement for discretionary services be changed from embedded cost so that each discretionary service is considered separately and priced at no lower than the incremental cost to provide the service. EGSI argued that pricing at incremental costs will ensure that no subsidies between discretionary services occur and that embedded costs may be difficult to determine. EGSI also argued that pricing at other than embedded cost is consistent with commission precedent. EGSI commented that it would be more appropriate to track revenues, rather than costs, associated with discretionary services as set forth in subsection (f)(1)(B)(iii) because revenues, regardless of costs, will be an offset in the determination of system services revenue requirement. EGSI further argued that if discretionary services are priced at no lower than incremental cost as requested, the utility will be required to prove that revenues exceed incremental costs.

OPC replied that EGSI's proposed changes would make it more difficult to determine whether ratepayers are subsidizing the provision of discretionary services. The commission will not know if cross-subsidization occurs. OPC argued that it would prefer to eliminate the "discretionary services" category and move all discretionary services into the competitive service category.

The commission declines to make the changes as suggested by EGSI. The commission finds that the pricing of discretionary services at fully allocated embedded cost is necessary to prevent cross-subsidization. The commission also disagrees with OPC's recommendation to eliminate discretionary services. The commission notes that discretionary services are not competitive energy services but distinct, customer-specific services in which the T&D utility should provide for the provision of system services. For example, as discussed under Preamble Question Number 13, the regulated utility must continue to own, install, and maintain all meters necessary for the energy measurements used in calculating an end-use customer's monthly electric charges after September 1, 2000. Therefore, the electric utility must also continue to provide certain customer-specific services necessary for the continued provision of this service (for example, meter testing, meter tampering, and meter re-reading charges) after both September 1, 2000 (as miscellaneous charges) and January 1, 2002 (as discretionary services) until T&D utility standard metering services become competitive.

EGSI commented that it is not clear which costs associated with "other services" must be tracked in subsection (f)(1)(D)(ii)(I) and reiterates its argument that "other services" should be priced at no lower than incremental cost. Enron commented that "other services" in subsection (f)(1)(D) are intended to maximize the value of the utilities' transmission and distribution system. These services must be evaluated in the same manner as any cost of service element recovered through the utility's transmission and distribution rates. Enron argued that it is necessary to track both the revenues and costs to assure that appropriate costs/benefits are applied to the service, to assure that the service is provided under a non-discriminatory tariff, and to assure that the service is provided at cost. Enron noted that tracking revenues only would not allow the test for inclusion of any incremental costs for ratemaking purposes to assure that maximum value is received by the utility for the provision of these services.

The commission agrees with EGSI that it may be very difficult to track all the costs associated with such services separately for some other services, such as cattle grazing. The commission will keep the scope of the "other services" very limited and will review them very carefully. The commission has revised the language in proposed §25.342(f)(1)(D) accordingly.

PG&E commented that precise definitions of services are critical and subsection (f)(1), which classifies each service that a T&D utility is allowed to prove, should be examined. PG&E stated that the commission should start with a "blank page" and then fill in the system services or functions that a utility should provide, rather than attempting to identify what utilities should not be providing. PG&E further recommended that rules should establish a rebuttable presumption that all non-system services are competitive energy services and, during the transition period, a conclusive presumption that the services are widely available. PG&E argued that the rules should expressly put the burden of rebutting that presumption on the utility.

The commission disagrees with PG&E and declines to make the changes recommended. As discussed previously, the commission finds that discretionary services are not competitive energy services but distinct, customer-specific services provided by the T&D utility.

The commission believes that the proceedings related to the separation of competitive energy services for September 1, 2000 will establish the appropriate line between services that are competitive energy services under proposed §25.343(d)(1) and services which will be discretionary services (after January 1, 2002). The commission notes that each utility will file, as part of its BSP-FP, a list of the proposed discretionary services to be provided by the transmission and distribution utility after January 1, 2002; the commission and affected parties may review the proposed discretionary services at that time and challenge a proposed discretionary service as being more appropriately classified as a competitive energy service.

PG&E suggested specific language changes to the definition of petitioned services in subsection (f)(1)(C), clarifying that a petitioned service may only be provided pursuant to a commission-approved tariff during the transition period.

As discussed under Preamble Question Numbers 7 and Number 9, the commission declines to limit the petition system to the transition period; therefore, the commission rejects PG&E's proposed changes.

Shell commented that subsection (f)(1)(D) may allow for potential T&D utility abuse. Shell commented that the utility should not increase its recoverable costs to provide "other services" and that the commission should require all "other services" to be provided pursuant to a commission-approved tariff to assure that the services are provided on a non-discriminatory basis. Shell argued that, minimally, the utility should notify a REP's competitors about the terms and conditions under which it provides "other services." Finally, Shell stated that the rule allows the utility to keep all "other services" revenues received outside of a test year, and this should be changed to require the revenues to be credited against utility's non-bypassable rates.

PG&E commented that the exception for "other services" in subsection (f)(1)(D) leaves a substantial potential for market abuse, unnecessary increases in rates for core transmission and distribution service, and the degradation of such services. PG&E suggests that "other services" should be limited to those products that utilize a portion of a utility asset or capacity; that such asset or capacity has been acquired for the purpose of and is necessary and useful in, providing tariffed utility services; that the involved portion of such assets or capacity may be used to offer the service without adversely affecting the cost, quality, or reliability of tariffed utility products and services; and that the services can be marketed with minimal or no incremental ratepayer capital, minimal or no new forms of liability or business risk being incurred by utility ratepayers and no undue diversion of utility management attention.

The commission notes that "other services" will be very limited in scope and will be approved only after careful review. The commission declines to make the changes suggested by PG&E and Shell, as they are unnecessary. The language of subsection (f)(1)(D)(ii)(II) states that services are to be offered pursuant to commission approved tariffs, if appropriate. This subsection is revised to reflect that the commission will determine if the tariff is appropriate.

CSW commented that subsection (f)(1)(D)(i)-(ii) should delete the word "existing" from the "other services" because, over time, a T&D utility will add facilities and employees.

The commission agrees with CSW that over time a T&D utility will add facilities and employees; however, the utility may not add facilities or employees for the sole purpose of providing "other services." The commission has incorporated appropriate language to clarify this provision.

CSW commented that subsection (f)(2) should be deleted because PURA §39.051(a) does not prohibit the utility from offering competitive energy services, but only requires them to be separated from regulated activities. In reply, OPC disagreed with CSW and stated that subsection (f)(2) is appropriate and consistent with PURA. OPC argued that the inclusion of this section is good public policy as it ensures that customers receive energy services in a competitive market environment and not from a regulated monopoly.

As previously discussed under the commission's recommendation under subsection (d), the commission agrees with OPC and declines to delete this paragraph.

PG&E commented that a new subsection (f)(3) should be added to establish a procedure that a utility must follow to petition the commission to classify a service as a discretionary service after the implementation of customer choice.

The commission finds that discretionary services will be proposed by each utility within its business separation plans and must be approved by the commission. As noted above, a discretionary service is not a competitive energy service but supports the provision of system services offered by the T&D utility. The commission believes that each proposed discretionary service to be provided by the transmission and distribution utility must be provided pursuant to a commission-approved tariff; therefore, the commission believes that there are adequate safeguards in place for the classification of discretionary services. In the event that a procedure needs to be implemented for the reclassification of system services and subsequently discretionary services to competitive energy services, the commission will establish a new rulemaking project for its implementation. However, the commission finds that PG&E's proposal is unnecessary and rejects its proposed changes.

§25.343. Competitive Energy Services.

Comments on subsection (a)

CSW commented that the prohibition against utilities offering certain competitive energy services conflicts with the requirements of PURA §39.051(a). CSW further commented that the petition process should recognize the continuing ability of a utility to offer both competitive energy services which are not widely available in the competitive market, and widely available competitive energy services that are fully separated from regulated utility activities. In response to CSW's comments, OPC commented that this section is consistent with PURA §39.051(a) and PURA §39.001(d), which reflects the legislators' preference for achieving the goals of deregulation through competitive methods.

The commission disagrees with CSW's interpretation of PURA §39.051(a). The commission finds that PURA §39.051(a) requires that on September 1, 2000, all customer energy services business activities already widely available in the competitive market be separated from the regulated utility. The commission believes that allowing regulated utilities to provide competitive energy services after September 1, 2000 is inconsistent with PURA §39.001(c), which states that regulatory authorities may not make rules or issue orders regulating competitive electric services. Furthermore, the commission agrees with OPC's comments and finds that

PURA §39.001(d) directs the commission to adopt competitive rather than regulatory methods to achieve the goals of restructuring whenever feasible. In this case, the commission finds the method which best promotes competition would be to prohibit the regulated utility from providing competitive energy services.

Comments on subsection (c)

Nucor proposed additional language which adds the phrase "except as authorized by the commission" to the end of this subsection. As discussed under Preamble Question Number 7 and Numbers 9, Nucor commented that this proposed language supports its position to permit utilities to offer competitive energy services under appropriate circumstances.

The commission declines to incorporate Nucor's proposed changes into this subsection. Subsection (d) as proposed provides a reasonable mechanism for affected utilities to petition the commission for an exception to provide a competitive energy service in a specified area if that service is not widely available to customers.

Comments on subsection (d)(1)

TIEC requested that the language in the section be clarified to add the word "unbundled" in order to state: "pursuant to a fully unbundled, embedded cost-based tariff."

The commission agrees with TIEC's comment and adopts this modified language.

EPE commented that customers would not pay fully embedded cost for utility-petitioned competitive energy services (for example, energy audits and bill analyses) even though the services are often desirable and beneficial. EPE suggested that such charges need to continue to be embedded in its wire charge if such services are to continue to be available in its service area. TNMP commented that the commission should reconsider the petition requirement in order for a regulated utility to provide competitive energy services.

The commission finds that EPE and TNMP's comments are not consistent with PURA §39.001 and the development of the competitive energy services market in Texas. The commission also finds that the petition system is reasonable. Therefore, the commission does not find it necessary to amend the proposed rule.

Nucor commented that a utility should be able to petition the commission to provide a competitive energy service if the utility believes that it is in the public interest to provide the service. Nucor proposed additional language for incorporation into the paragraph.

The commission is not persuaded by Nucor's comments and rejects its proposed language. The commission finds that Nucor's proposed language would inappropriately broaden the statutory standard by allowing the utility to petition the commission to provide a widely-available competitive energy service based upon a generic "public interest" or "reliability" standard. The commission believes that PURA §39.051(a) clearly articulates the public interest in stating that the regulated utility may not provide competitive energy services on and after September 1,

2000. The commission believes that proposed §25.343(d)(1) is reasonable and supports the public interest by allowing an affected utility to petition the commission to provide a competitive energy service if the service is not widely-available in a given area.

TXU commented that the commission, in its consideration of a utility's petition to provide a competitive energy service, should take into account the potential positive impact the service will have upon the reliability of the customer's system and the transmission grid. TXU proposed additional language for incorporation into this subsection. Shell recommended that the commission reject TXU's recommendation because listing criteria in a rule unduly limits the commission's discretion; therefore, the commission should develop criteria on a case-by-case basis. EGSI commented that the factors to consider in granting a utility's petition to provide competitive energy services during the transition period (September 1, 2000 to January 1, 2002) should include public interest concerns such as reliability and transitional impacts. EGSI proposed additional language for incorporation into the subparagraph. In response to EGSI's comments, OPC disagreed with EGSI and stated that if the service is not available, EGSI should petition the commission to provide the service.

The commission declines to incorporate the changes proposed by EGSI and TXU. The commission finds that EGSI and TXU's proposed changes inappropriately broaden the utility's provision of competitive energy services. Furthermore, as discussed under Preamble Question Number 8, while the commission agrees that reliability of the transmission and distribution system should be maintained in Texas, the commission is not persuaded that the regulated utility provision of *widely-available competitive energy services business activities* is necessary for maintaining system reliability. The commission believes that it is in the public interest and mandated by PURA §39.051(a) to separate competitive energy services from the regulated utility on and after September 1, 2000. The commission believes that proposed §25.343(d)(1) is reasonable in that an affected utility may petition the commission to provide a competitive energy service if the service is not widely-available in an area.

EGSI commented that the second sentence of paragraph (1) states "the utility has the burden to prove to the commission that the service is not widely available in that area due to market barriers outside of the utility's or the commission's control to correct." EGSI commented that this burden of proof should not be the sole criterion upon which a petition to provide competitive energy services is approved; however, this factor may be one of several factors considered by the commission in reviewing an affected party's petition. EGSI proposed to amend the second sentence of paragraph (1) to state: "The utility has the burden to prove to the commission that the service should be offered by the petitioner due to public interest concerns such as reliability and transitional impacts."

The commission agrees in part with EGSI that the phrase "due to market barriers outside the utility's or the commission's control to correct" is better placed as one of the factors the commission may consider when reviewing a utility's petition. However, the commission disagrees that the utility's burden of proof should be deleted or replaced by EGSI's proposed language. The commission finds that EGSI's proposed change inappropriately broadens the utility's ability to offer competitive energy services. The commission finds that the burden of proof should more closely track the "widely available" standard within PURA §39.051(a) and amends the second sentence under subsection (d)(1) accordingly.

EGSI commented that the commission should provide guidance on how the "widely available" burden is satisfied. EGSI suggested language for incorporation into the subparagraph which requires the petitioner to demonstrate or consider the following factors during a petition proceeding: (1) geographic factors; (2) demographic factors; (3) number of vendors offering the same service; (4) ability of vendors to displace the provision of the service by the utility, assuming the utility ceases to offer the service and no affiliate of the utility assumes the offering of the service; (5) practicality of individual customers purchasing the service as a separate service; and (6) whether existing market barriers, if any, are outside of the utility's and commission's reasonable ability to correct.

Under Preamble Question Number 7, TIEC commented that the commission should adopt objective criteria to determine whether a specific energy service is "widely available" under SB7. TIEC further commented that an energy service should be classified as widely available if there are one or more existing competitors in a region that are capable of providing the service.

The commission agrees in part with TIEC and EGSI that some guidance is necessary in order for affected utilities to prepare meaningful petitions under this subsection; however, the commission also concludes that the factors to be considered cannot fully recognize all petitionable services. The commission will adopt the following factors which the commission *may* consider, but is not limited to considering, when reviewing a utility petition under subsection (d)(1)(A):

(i) geographic and demographic factors;

(ii) number of vendors providing a similar or closely-related competitive energy service in the area;

(iii) whether an affiliate of the affected utility offers a similar or closely-related competitive energy service in the area;

(iv) whether the approval of the petition would create or perpetuate a market barrier to entry for new providers of the competitive energy service;

To improve clarity, the commission reorganizes this subsection into subparagraphs.

Reliant commented that it would be impractical to provide some competitive energy services pursuant to a tariff (for example, economic development, advertising, and customer education activities). Reliant proposed a rewritten third sentence, which allows the utility to provide petitioned services as part of "system service" tariffs unless the commission finds otherwise. In response to Reliant's comments, Shell stated that the commission should reject Reliant's proposal because separate tariffs provide a transparent, non-discriminatory price for customers and allow the commission to review the rates for particular services.

The commission agrees with Shell and rejects Reliant's proposed changes. The examples given by Reliant have been removed from the definition of competitive energy services as discussed above.

Shell commented that the petition system should not rely on a utility's findings of certain conditions. Shell proposed new language for incorporation into this subparagraph.

The commission agrees with Shell's comments and adopts a modified version of Shell's proposed language for incorporation into the rule. The commission replaces the first sentence of this subsection to read "A utility may petition the commission to provide on an unbundled tariffed basis a competitive energy service which is not widely available to customers in an area."

PG&E proposed additional language which establishes a conclusive presumption that a competitive energy service is "widely available" during the transition period if, in response to a utility filing a petition to provide a competitive energy service, a non-affiliated REP notifies the commission that the REP is or will immediately commence providing the same competitive energy service in the same market.

The commission finds that PG&E's proposal would restrict the commission's discretion when reviewing a petition, and therefore rejects the proposal. The commission believes that each petition should be considered on a case-by-case basis. The commission finds that a retail electric provider's provision of closely-related competitive energy services within an area would be one significant factor considered by the commission when reviewing a utility's petition to provide a competitive energy service.

Comments on subsection (d)(2)

Nucor proposed additional language that allows an affected person or the commission to initiate a petition for the utility to provide a competitive energy service when it is in the public interest to do so.

As stated under subsection (d)(1) comments, the commission is not persuaded and rejects Nucor's proposed language for incorporation into the rule.

As discussed under EGSI's comments under subsection (d)(1), EGSI wants the commission to provide guidance on how the "widely available" burden is satisfied. EGSI suggested language for incorporation into the subparagraph which requires the petitioner to demonstrate or consider certain factors during a petition proceeding.

As noted previously under subsection (d)(1), the commission agrees with EGSI's proposed considerations in part and adds an additional sentence to subsection (d)(2): "The commission may consider, but is not limited to considering, the factors pursuant to paragraph (1) of this subsection (where applicable) when reviewing a petition under this paragraph."

Comments on new subsection (d)(3)

EPE commented that many of the energy services defined as competitive may not in fact be competitively available in EPE's service area. Thus, the rules would either cause such services to disappear altogether in some areas or would impose a potentially costly and burdensome petition process simply to allow utilities to continue to provide those important services to their customers. EPE proposed language for a new paragraph that establishes a mechanism that would allow reversal of the presumption, inherent in the proposed rules that all energy services are available competitively unless proven otherwise. EPE commented that this new paragraph would allow utilities to demonstrate that as a general matter energy services are not competitively available to a significant portion of their customers.

The commission disagrees with EPE's proposed changes. The commission finds the petition system under paragraph (1) to be reasonable. The commission does not believe that the petition system will be overly burdensome as suggested by EPE.

Comments on subsection (e)

Enron supports this subsection, which requires the utility to provide a detailed plan for completely and fully separating competitive energy services as part of the BSP-FP. In reply comments, Shell commented that affected utilities may petition the commission to provide or secure permission to offer competitive energy services in the January 2000 unbundling proceedings.

The commission agrees with commenters that detailed separation plans and petitions should be included within the business separation plans to be filed on January 10, 2000. The commission concludes that this subsection be revised to clarify that a utility's business separation filing should include a utility's petition(s), if any, to provide a competitive energy service(s) as prescribed by proposed subsection (d)(1). For purposes of clarity, the commission amends subsection (e) and divides the subsection into three separate subparagraphs. The commission also adds a new paragraph to clarify the requirement that affected utilities provide cost information pertaining to the separation of competitive energy services pursuant to proposed §25.344 and the Unbundled Cost of Service Rate Filing Package (UCOS-RFP).

§25.344. Cost Separation Proceedings.

Reliant stated that the list of non-bypassable charges in the last sentence of §25.344(c)(1) should be amended to include metering system service charges and customer service system charges. CSW stated that energy efficiency expenses incurred to achieve the efficiency goals of SB7 should also be included. Reliant also suggested using the term "filings" rather than "tariffs" to describe the supporting information, and the addition of the word "nuclear" before "decommissioning" for clarity. EGSI concurred with the substitution of "filings" for "tariffs".

The commission agrees with the commenters and adopts the proposed language.

TXU commented that the term "stranded cost charges" should be defined to include both "competition transition charge" and "transition charge" for recovery of securitized assets. An alternative solution, also proposed by TXU, would be to state in the rule that "transition charge" for recovery of securitized assets is included in the meaning of "competition transition charge". DFWHC/CICU stated that the latter would be an imprudent revision of the rule, with the potential for unintended consequences.

The commission has adopted TXU's recommendation that "stranded cost charges" should be defined to include both "competition transition charge" and "transition charge" for recovery of securitized assets. The commission has added "stranded cost charges" to proposed §25.341(21) and modified §25.341(5) to include transition charges unless the context indicates otherwise.

Reliant recommended inserting the word "projected" before the phrase "12-month period ended December 31, 2002" in the definition of forecast year in §25.344(d)(2).

The commission adopts Reliant's proposed change.

TIEC opposed a default range of acceptable rates of return and believes that the rate of return to be used should be based on current information specific to each utility. (§25.344(e))

The commission disagrees with TIEC and declines to change the proposed §25.344(e), as discussed in the preamble to the Unbundled Cost of Service Rate Filing Package (UCOS-RFP).

TXI stated that §25.344(e) should require each utility to file separate rates of return for competitive and non-competitive services. TXU disagreed with TXI, stating that the commission will no longer set rates of return for the transmission and distribution utility's affiliated generation company or affiliated retail electric provider after January 1, 2002.

The commission disagrees with TXI and declines to change the proposed §25.344(e).

CSW stated that clarification is needed in §25.344(f)(2) with regard to school funding loss mechanisms. TXU proposed the addition of the language "to the extent that recovery is authorized by PURA §39.903" to the description of the adjustments to historic year costs for future recovery through the system benefit fund. TIEC stated that the proposed rule should specify that all costs associated with the system benefit fund (SBF) should be allocated based on class energy consumption at the generator, that these costs should be recovered on the basis of energy consumption, and that the associated fee should be differentiated by voltage level.

The commission agrees with some of TIEC's suggestions and adds a new subparagraph (F) to §25.344(h)(2) to the effect that costs associated with SBF shall be allocated based on the customer's actual energy consumption adjusted for voltage level losses.

The commission agrees with TXU and amends §25.344(f)(1) and (4) to the effect that the SBF fee will be established and implemented pursuant to PURA §39.901 and §39.903. The commission also agrees with CSW and revises the language to clarify the treatment of the historical cost information related to school funding mechanisms. Utilities are required to report the property taxes paid in the historical test year as a separate line item to enable the calculation of how the taxes will decrease as a result of the restructuring.

TXU stated that §25.344(f)(3)(E) should be deleted, because PURA does not authorize any costs other than those listed in subparagraphs (A)-(D) to be recovered through the System Benefit Fund.

The commission disagrees with TXU and declines to delete proposed §25.344(f)(3)(E).

Shell commented that §25.344(g)(1)(A) should explicitly state that the transmission and distribution utility bears the burden of proof that its affiliate-related expenses comply with the requirements of this rule.

The commission determines that there is no need to change the wording of the rule. The rule states that the requirements of PURA §36.058 will be met, which places the burden on the utility to prove its affiliate expense. Further elaboration is not necessary.

TXU and CSW stated that information about affiliate transactions required by §25.344(g)(1)(B) should be limited to transactions which are either directly between the T&D utility and the non-regulated affiliate, or are shared by the T&D utility and the non-regulated affiliate, and that the rule should be amended to clarify this.

The main interest of the commission is to review the transactions between the regulated utility and the non-regulated affiliates. However, this section of the rule addresses the services company. To evaluate the allocation of expenses between the service company and the regulated utility, the commission must know the allocation formulas and their basis, as well as have access to the charges to the non-regulated utility. This is necessary to evaluate the "reasonableness" of the affiliate expenses. The commenters' proposal to limit affiliate reporting to the transactions between the regulated and non-regulated affiliates would not be appropriate not sufficient in this section as it is limited to the affiliated service company. Therefore, the commission declines to make the suggested changes.

CSW commented that many of the categories listed in §25.344(g)(2) are not regulated, and competitive harm could result from the separation of non-regulated functions. TIEC stated that §25.344(g)(2) should require utilities "to unbundle the costs associated with each of the ancillary services they are required to provide under the commission's wholesale transmission rules."

The commission notes that SB7 requires utilities to separate unregulated activities into a power generation company and a retail electric provider. Therefore, to require aggregated reporting of costs for these two functions would be inappropriate, and the commission declines to amend the proposed rule in response to CSW's comments.

Enron and CU/TLSC/Texas ROSE stated that the methodology in §25.344(g)(3) of the proposed rule, along with the separation of functional costs into the eight categories specified in §25.344(g)(2), is necessary to ensure that customers in an open access environment are not paying rates for regulated services which recover costs for competitive services. Shell suggested clarifying language for references in this paragraph to common costs.

The commission agrees with the commenters, and further notes that the functions "generation" and "competitive energy services" do not encompass all unregulated functions. Therefore, the commission has amended the rule to include a category in which costs for unregulated services which do not belong in either generation or competitive energy services may be recorded.

Reliant and EGSI recommended changing all occurrences of the term "allocator" in §25.344(g)(3) to "functionalization factor," as well as changing the word "allocation" to either "assignment" or "functionalization," as appropriate. Additionally, Reliant and EGSI suggested the addition of the concept of "appropriate cost-causation principles" in the derivation of account-specific functionalization factors. Finally, Reliant stated that the phrase in §25.344(g)(3)(C) which reads "for which no direct assignment or account-specific allocation is possible" should be changed to "for which direct assignment or account-specific functionalization cannot be identified." These changes are for purposes of consistency between the Unbundled Cost of Service Rate Filing Package and the proposed rule.

The commission agrees with the commenters and adopts the suggested language.

TIEC stated that §25.344(h) should be amended to clarify that all regulated utility functions, not only transmission and distribution (as specified in §25.344(g)(2)), should be forecast and allocated using the 2002 test year. TXU disagreed with TIEC, asserting that a separate forecast for each function, rather than a single forecast for the aggregate of all regulated functions, would be overly burdensome with little benefit.

The commission agrees with TIEC and has adopted its suggested language.

EGSI stated that using the term "existing rate classes" with reference to a forecast year is inappropriate, and that the word "existing" should be deleted. To provide consistency with the

UCOS-RFP, as well as to avoid issues relating to FERC jurisdiction, EGSI also recommended that §25.344(h) require that each non-ERCOT utility "provide a copy of its FERC filing for an unbundled transmission rate for application in Texas for the forecast year", rather than allowing such utilities to "allocate transmission revenue requirement based on either FERC-approved methodology or the methodology approved in the last commission-approved cost of service study." TIEC disagrees with EGSI's proposed changes, asserting that forecasting based on existing classes is necessary to determine the impact of unbundling on existing rate classes. TIEC also proposed that the commission take an active role in FERC transmission cases to assure that the commission's policy closely tracks that of the FERC in order to avoid adverse effects on customers resulting from disparate regulatory policy.

The commission agrees with TIEC and determines that cost allocation for the regulated functions, whether historical or forecast, must be done before the utility's proposed class consolidation. Therefore, the commission declines to make the changes suggested by EGSI.

With respect to §25.344(h)(2)(A), Shell stated that the commission should ensure in cost separation proceedings, wholesale transmission costs are not improperly assigned to retail customers.

The commission agrees with Shell's concern, but it does not necessitate any change to the rule.

Shell stated that in subparagraphs (B)-(E) of §25.344 (h)(2), references to the "last cost of service study" should be changed to "last commission-approved cost of service study" to "avoid any possible claim that rates should be based on a rejected cost of service study."

The commission disagrees that Shell's proposal improves the clarity of the rule. However, the commission has amended the referenced subparagraphs for the purpose of internal consistency.

TXI suggested language to replace the reference in §25.344(h)(2)(A) to "the average four coincident peaks" with language that requires utilities to provide estimates of each existing class' contribution to the average of the four ERCOT peaks.

The commission agrees with TXI that class-specific contributions to the ERCOT four coincident peaks is the most relevant allocator for transmission costs. However, this information may not be available for classes which are not demand-metered unless utilities perform load analysis. The commission declines to make the changes suggested by TXI.

For §25.344(i)(2), EGSI proposed language to "more accurately reflect the exclusiveness of FERC jurisdiction". Specifically, the reference to open access transmission tariffs should be replaced by the language "costs, rates, terms and conditions for transmission service…in effect on the dates such transmission service is provided."

Proposed §25.344 deals with only the separation of costs. Therefore, the commission finds that EGSI's proposal to reference the terms and conditions of the FERC tariff are not necessary.

Cities stated that the language "usage of the transmission and distribution systems" in §25.344 (j) was too vague, and should be amended to recognize that consolidation should be based upon the goal of homogeneity within classes. Shell stated that "class consolidation should not cause some customers to pay materially greater non-bypassable rates than they would pay absent consolidation." Shell further stated that its interpretation of "materially disadvantaged" is that "any increase above a *de minimus* amount materially disadvantages a customer class."

TXI proposed that the threshold for "materially disadvantage" of a class be set at 5.0% of total costs assigned to that class; Shell agreed and further suggested that parties may establish that a greater or lesser percentage constitutes material disadvantage.

TIEC stated that §25.344(j) should be amended to require that "class consolidation should not materially disadvantage any customer, not just any customer class," and that factors in addition to usage should be considered in consolidating classes. Shell recommended that TIEC's proposal be rejected, asserting that a customer-by-customer analysis of consolidation would be logistically unfeasible.

Commercial Associations commented that the net result of consolidation on a particular class may not reflect detrimental effects on individual customers, and that a customer impact study should be required by the rule. Nucor stated that maintaining existing rate classes would "reduce the likelihood of unfairly disadvantaging particular customers and customer classes," however, Nucor did recognize the benefit of simplification by consolidation of classes. Nucor stated that this goal would be accomplished through a separate per-kWh rate design for each existing customer class.

The commission disagrees with the Commercial Associations and in general, believes that the customer classifications from the traditional regulatory paradigm will be less relevant in a competitive marketplace than they are today. This is particularly true if prior T&D cost allocations were not consistent with cost causation principles. The commission generally agrees with Nucor that the benefits of class consolidation and the potential impact on customers must be balanced. Therefore, the commission believes that it is premature to specify limitations on the parameters of class consolidation in this rule as it will be better able to evaluate the benefits and implications of class consolidation with real facts before it.

§25.345. Recovery of Stranded Costs Through Competition Transition Charge.

Enron stated that it supports the development of the CTC that: (1) ensures recovery of stranded costs as quickly as possible, (2) remains competitively neutral, (3) does not penalize customers who improve their use of the utility's system, and (4) does not harm customers due to changes in customer classification or intra- and inter class load shifts.

OxyChem generally supports the TIEC's comments on the proposed rules.

TXU and Reliant commented on the inconsistency in terms used relating CTC, TC and stranded costs charges through out the rules. (see TXU §25.344 comments)

The commission agrees with TXU and Reliant that the term CTC should be used consistently throughout the rules. The definition of CTC in proposed §25.341(5) has been revised to include the transition charges pursuant to PURA §39.302(7). In addition, the term stranded costs charges have been defined in proposed §25.341 to include transition charges and competition transition charges.

Subsection (a) Purpose

TXU stated that list of statutory provisions implemented under this section should include Subchapter G of Chapter 39 relating to securitization.

The commission agrees with TXU and proposed rule has been amended accordingly.

Subsection (e) Recovery of stranded costs from wholesale customers

Shell stated that during the task force process the utilities improperly shifted wholesale stranded costs to retail customers by zeroing out wholesale energy consumption. Shell suggested the rule clearly state that if the utility decides not to recover some or all stranded costs from its wholesale customers, it cannot recover its stranded costs from retail customers. TIEC supported Shell's proposal.

Reliant objected to Shell's suggestion and urged the commission to reject Shell's proposal. According to Reliant, Shell's proposed language imposes a constraint upon stranded cost recovery that does not appear in SB7 and, if implemented, would violate PURA §39.252(a). Reliant stated that the power contract it had to sell firm capacity to TNMP will terminate in July 2001. It would be both unfair and unlawful to preclude recovery of stranded costs based upon the premise that some portion of Reliant's stranded costs should continue to be allocated to a wholesale customer that historically purchased firm power from the company, but no longer will do so. Reliant added that if the commission determines that a wholesale purchaser of firm power should have an ongoing obligation to contribute to the recovery of stranded costs beyond the terms of existing contracts, the commission should affirmatively address the scope of such an obligation in this rulemaking. Reliant also recommended including *"wholesale"* before the phrase stranded costs in the second sentence.

The commission agrees with Shell and Shell's proposed language has been incorporated to the rule. PURA §39 provides mechanisms for a utility to recover its retail stranded costs from its retail customers and at the same time does not alter the right of a utility to recover stranded costs from wholesale customers, as stated in PURA §39.265. Some utilities have built capacity to serve their firm wholesale customers, and costs associated with these plants have been allocated historically to the wholesale customers in the past cost of service studies. Whether a utility pursues the recovery of stranded costs from a wholesale customer *beyond* the term of contract is not an issue in this rule. All that needs to be determined is the level of retail stranded costs to be recovered from retail customers.

Subsection (f) Quantification of stranded costs:

Enron stated that it is imperative that forward price quotes capture the load factor-profile of a combined cycle combustion turbine generator as a resource addition to serve the native load of each respective utility. Enron also noted that to ignore the seasonality of natural gas prices as contemplated in the UCOS-RFP will result in artificially low price quotes and higher ECOM. Shell stated that rule should be revised to clarify that the estimated environmental clean up costs should not be included at the time initial CTCs are set.

The issue of natural gas prices was addressed by other parties in the development of the Unbundled Cost of Service Rate Filings Package (UCOS-RFP). The commission has responded to the issue in the preamble of the UCOS-RFP. The quantification of the environmental costs will be addressed in Project Number 21406, *Standards for Recognition of Costs of Environmental Clean-up or Plant Retirement*, which is the appropriate forum for Shell to raise its concerns.

Confidentiality

TXI proposed additional language to this section to ensure that this rule does not unintentionally provide utilities with a level of confidentiality beyond that accorded in the UCOS-RFP. TIEC stated that the language is ambiguous and it opposes strongly the suggestion that a utility has legal right in a contested case to prevent any review of alleged confidential information, even under a protective order.

Enron stated that all stakeholders should have reasonable access to all data and information used in the ECOM model. Enron recommended that the commission should establish that improper use of protective orders would not be tolerated in any proceeding related to restructuring.

The sentence referring to confidentiality has been deleted. Given the comments, the commission believes that the issue of confidentiality is best addressed through the use of a protective order. The commission is developing a standard protective order in Project Number 21662, *Development of a Standard Protective Order for Use in SB7 Transition Cases*.

Subsection (g) Securitization

Shell stated that the initial securitized CTC applicable during the freeze period should apply only on an interim basis. Shell also stated that the commission should require utilities to pay off securitization bonds over the longest approved time period. CSW suggested that the rule should include an expedited procedure with specific time frames to prevent that process from being protracted.

The nature and duration of the initial securitized CTCs will be addressed in the securitization proceedings. SB7 allows for a securitization period of up to 15 years, but the commission has the discretion to order a shorter securitization period if such shorter time period is deemed prudent. The commission disagrees with CSW and notes that the procedural schedule will be decided on a case by case basis in the various securitization proceedings.

Subsection (h) Allocation of stranded costs

Enron recommended that the proposed rule specify the method by which ECOM is to be allocated and what supporting documentation is to be included in UCOS-RFP.

Commercial Associations proposed insertion of the phrase *"factors resulting from"* so that it would be clear what was meant by methodology. Cities repeated their support for allocation based on the specific numeric demand allocators from the last rate case.

TIEC stated that if an agreement is not reached in negotiations among the parties relating to ECOM, language in this section should be clarified so that fixed numeric allocators are not to be used. TIEC also indicated its opposition to Commercial Associations' proposal.

The commission discussed its decision related to allocation of stranded costs in answers to Preamble Question Numbers 1, 2 and 3. No change to proposed §25.345(h), except for §25.345(h)(2)(B)(v), is needed. Subsection (h)(2)(B)(v) has been revised to reflect the commission's decision on the development of the energy allocator. A new subsection §25.345(h)(2)(B)(vi) has been added to reflect the commission's decision regarding the development of stranded cost allocation to special rate classes.

Proposed §25.345(c) and (i): Applicability of CTC to customers receiving power from new on-site generation or eligible generation

General

OPC commented that proposed language to address on-site generation is incompatible with PURA §39.252(b) or §39.262(k). OPC added that it is important for the proper allocation and recovery of stranded costs that the commission rules relating to on-site generation maintain the narrow exception found in PURA §39.262(k), and foster the general principle that all existing and future retail customers contribute to stranded cost recovery. Shell and Cities stated that they support OPC's comments.

TIEC, Alcoa, OxyChem, Enron, OAG objected to OPC's suggested changes and stated that the published rule was developed by a task force of diverse participants, including OPC and utilities. These parties noted the only non-consensus item was §25.345(i)(5), relating to Multiple On-site Facilities. According to these parties, OPC's proposal would fundamentally change the language in the consensus parts of the rule, and therefore should be rejected.

Effective Date to be eligible for Exemption from CTC for facilities less than ten MW

According to OPC, Shell, and Cities, by using a past tense in phrase "*has been* lawfully served" (emphasis added), the express language of PURA §39.262(k) necessarily requires lawful service of the customer's actual load by that facility to have started in the *past*, before a particular point in time. These parties noted that absent a specific defined date in the statue ,the best possible date for the particular time would be the effective date of statute, September 1, 1999. Therefore, the exception in proposed subsection (i)(2) should not apply to some future date or event, but should only apply to customer loads that began receiving service from such facilities *before* September 1, 1999.

Alcoa, OAG, Enron, OxyChem, TIEC, NewEnergy, and Sonat objected to OPC, Cities and Shell's comments and stated that in order to encourage the development of distributed generation pursuant to PURA §39.101(b)(3), the Legislature intended to create a continuing exemption for small (ten MW or less) power production facilities. According to these parties, PURA §39.252(b)(1) defines new on-site generation which is not exempt from CTC as *"electric generation capacity greater than ten MW*". OPC's proposal would make this definition superfluous and would have the exemption for facilities less than ten megawatts read out of the statute by limiting it to the distributed generation existing on the effective date of SB7. These parties noted the exemption in PURA §39.262(k) should not be isolated from the rest of the statute, particularly PURA §39.252(b)(1). These parties stated that, pursuant to PURA §39.252(b)(1), only self-generation that falls within the definition of "new on-site generation" is subject to stranded cost recovery. By expressly removing generation capacity of ten megawatts or less from the definition of new on-site generation, the Legislature created the ten-megawatt exemption. According to Sonat, PURA §39.262 is related to the true-up proceedings and therefore the phrase "has been", as used in that section, to refers events which occur before the true-up proceedings. OAG added that nothing in the statute expressly states that small distributed generation facilities must already be completed and operational before September 1999 in order to qualify for the exemption. According to OAG, the issue is whether the load has been served at that time, "after the facility becomes fully operational", not whether the load has been served prior to September 1, 1999.

The commission disagrees with OPC, Shell, and Cities, and determines that correct reading of PURA §39.252(b)(1) and §39.262(k) together requires the exemption for the facilities less than ten megawatts to apply to future on-site generation, not merely that were in place on September 1, 1999. By giving this exemption, the goal of the Legislature was to encourage distributed generation. Therefore, the commission declines to make the changes suggested by OPC.

Subsection (i)(5) Multiple on-site power production facilities and language proposed by NewEnergy

NewEnergy proposed language for multiple on-site power production facilities with multiple units each unit less than ten MW. NewEnergy stated that its proposed language recognizes the intent of the Legislature to encourage distributed generation. According to the language proposed by NewEnergy, a customer who has multiple units (such as three four-MW units) will designate its own exempt units and non-exempt units will be separately metered. The customer will pay a CTC based on the output of non-exempt units, as contemplated by PURA §39.252(b)(1). (For example, a customer with three four-MW units can designate an eight MW exempt facility and a four MW as non-exempt new-onsite generation). NewEnergy also added language to prevent customers from creating separate entities for the purpose of gaining multiple exemptions or otherwise "gaming the system". TIEC, OxyChem, Alcoa, NAESCO, Enron, Sonat and El Paso Gas stated their support for the language proposed by NewEnergy.

CSW stated that statutory exemptions from paying for stranded costs should be narrowly construed to reach a reasonable result that can be practically administered. CSW added that the language proposed by NewEnergy is consistent with these goals. Reliant stated that, absent an agreement of the parties, Reliant would support a provision that defined the parameters for multiple on-site facilities as clearly as possible, while allowing for a case-by-case resolution of the inevitable "gray" areas. TIEC, Alcoa, and OxyChem also stated that, absent an agreement among the parties, they would support retaining the place-holder language in the proposed rule, and leaving the resolution of multiple on-site generation to be decided in the future on a case-by-case basis, should the necessity arise. TXU stated that it agrees with the language proposed by NewEnergy. However, TXU noted that if a single site had both eligible and non-eligible facilities, then the production from *all* of the facilities on the site should be used to determine whether or not the new onsite generation results in a material reduction in the retail customer's energy usage. In other words, if the facilities at a single site would meet the *"material reduction"* threshold defined in proposed §25.345(i)(4), the fact that some of those facilities might be exempt from CTCs as being eligible facilities would not cause the other facilities to go below *"the material reduction"* and also be exempt from paying CTCs.

OPC objected to NewEnergy's proposed language for the placeholder in §25.345(i)(5) relating to multiple on-site generation. According to OPC, NewEnergy's proposed language contradicts the express statutory language in PURA §39.262(k). This statutory provision is limited to a *single* on-site power production facility. OPC's alternative language would allow multiple generation units as long as they are connected, maintained and operated as a single power production facility, as PURA §39.262(k) requires. OPC added that under NewEnergy's proposal, a customer could utilize three five-megawatt on-site facilities, using two facilities to provide primary service to its load and using the third facility to provide stand-by service to the load. In this example, the third facility, by providing only stand-by service would have no output upon which to base a CTC. Thus, NewEnergy's proposed rule converted the PURA §39.262(k) exception for a ten MW or less facility into a fifteen MW rated facility. OPC argued that many other scenarios exist under NewEnergy's language, which contravenes the express language of PURA. OPC also opposed NewEnergy's proposed mechanism to allow a customer to designate and re-designate the eligible generation facilities. According to OPC, this mechanism cannot be realistically monitored by the commission, is unenforceable, and does not promote simplicity.

NewEnergy disagreed with OPC's argument that if the third unit is built as back-up for the first two units, a standby CTC must be assigned to that unit. NewEnergy stated that the legislature provided only one mechanism, namely based on the output of the unit, for collecting a CTC from "new on-site generation" and that mechanism should prevail.

The commission generally agrees with parties supporting the language proposed by NewEnergy. However, the commission finds that it is appropriate to revise NewEnergy's proposed language to incorporate the changes suggested by TXU, and has incorporated this revised language in the rule. The commission also agrees with OPC that the exemptions provided by PURA to avoid the CTC must be narrowly defined. However, PURA §39.252(b)(2) only mandates a CTC for the new on-site generation based on the *output* of the non-exempt facility. If the non-exempt facility is used as stand-by, there is no way of assigning a CTC to that facility. The commission finds that because of the economics, it would be a rare situation where a customer builds a facility for solely standby purposes.

Enron suggested that the commission establish procedures to evaluate multiple on-site generation units to determine if the purpose of encouraging development of on-site generation through CTC exemption is met.

The commission disagrees with Enron because there is no immediate need to conduct such an evaluation.

Mutually exclusive nature of qualifying facilities (QF) exemption and ten MW exemption:

OPC stated that because of the way the proposed rule is structured, proposed §25.345(c)(2) and §25.345(i)(2) result in a new, broader exception not authorized in PURA §39.262(k). According to OPC, PURA §39.262(k) delineates only two, *mutually exclusive*, limited circumstances, each of which contains its own criteria for application of its exception. According to OPC, if a customer is served by a QF and a facility less than ten MW, it should be eligible for only one of these exemptions. NewEnergy, Alcoa, TIEC and OxyChem objected to OPC's argument that the exemptions in §39.262(k) are mutually exclusive. According to NewEnergy, the same customer may own both an exempt qualifying facility and an exempt distributed generation facility. According to these parties, the more logical interpretation is that the word "or" was intended simply to make it clear that there are two separate exemptions in the provision. Sonat stated that the Legislature intended *each* customer to receive up to ten MW of exempt self-generation as an incentive to use distributed generation.

The commission disagrees with OPC and determines that the two exemptions are not mutually exclusive. Therefore, no changes to the proposed rule are necessary.

Definition of Retail Customers with no CTC

OPC proposed the deletion of proposed §25.345(c)(2) relating to definition of eligible generation and §25.345(i)(1) relating to defining customers who will not be assigned *any* CTC. In support of its proposal to delete these paragraphs, OPC stated that PURA §31.002(16) defines *retail customer* as "the separately metered end-use customer who purchases and ultimately consumes electricity". By this statutory definition there is no such thing as "a retail customer who does not receive any electric service that requires the delivery of power through the facilities of a T&D utility" as described in the proposed rule. According to OPC, this language conflicts with PURA §39.253(i), which states that no customer or customer class may avoid the obligation to pay stranded costs allocated to that class except as provided by PURA §39.262(k). OPC noted that §39.262(k) says nothing about the kind of customer described in proposed §25.345(i)(1). OPC also provided revised language to replace proposed §25.345(i)(1).

OxyChem and TIEC responded to changes recommended by OPC to proposed §25.345(i)(1), regarding to the definition of a retail customer. These parties are opposed to the deletion of this paragraph. OxyChem noted that it would not have any objection to substituting a term such as "end-user" for "retail customer." TIEC stated that SB7 is clear that if a customer uses generation defined as eligible generation and purchases no services from the utility, it will pay no stranded cost.

The commission finds that the language in proposed §25.345(i)(1) is necessary to address situations where a customer who is *not* using new on-site generation. For example, if a self-generator fully disconnects from the transmission and distribution grid. The commission agrees with OPC's argument that such a user can no longer be defined as a retail customer of the T&D utility. However, the commission finds that OxyChem's proposal to replace the term with "end-user" is more appropriate than deleting the paragraph. The commission also determines that in order to narrowly define the exceptions in PURA, it is necessary to revise the language to make it clear that the exemptions are only assigned to the initial customer. If the initial customer sells or otherwise discontinues operation of the facility, the replacing customer is not entitled to receive the exemptions. To make this clear, changes have been made to the definition of eligible generation in proposed §25.345(c)(2).

Definition of a facility less than ten MW

OPC and Shell commented that the issue is whether the exception under PURA §39.262(k) should apply to a customer whose actual load has been served by multiple on-site power production units that *individually* have a rated capacity of less than ten megawatts but cumulatively have a total rated capacity that exceeds ten megawatts. According to OPC, from the express language of PURA §39.262(k), it can be logically ascertained that the exception would not apply to a customer whose actual load has been served by multiple power production units unless 1) the units have been connected, maintained and operated as a single power production facility in serving the customer's actual load, 2) the cumulative total of the rated capacities of such units does not exceed ten megawatts 3) power from the units is capable of being lawfully delivered to the site without use of utility distribution or transmission facilities and 4) the customer's load has not been served by a qualifying facility described in PURA §39.262(k). OPC provided revised language to implement its recommendations. Shell stated that the commission should not allow industrial customers to "escape" the CTC if they operate on-site generation of ten MW or greater capacity.

NewEnergy, Alcoa, OxyChem, TIEC, Enron and Sonat objected to OPC's suggestion to eliminate the entire ten MW exemption if a customer crosses the ten MW threshold. According to NewEnergy, the Legislature gave *every customer* an exemption up to ten megawatts. If a customer operating two four MW distributed generation units were to lose the entire exemption because he added a third four MW unit, he would realize none of the incentive that the Legislature intended. NewEnergy noted that, under its proposed language, the third four-megawatt unit described in the example would be considered "new on-site generation" and the customer would receive only an exemption of eight MW.

The commission notes that PURA §39.252(b)(1) defines new on-site generation as "electric generation *capacity* greater than ten MW", whereas §39.262(k) uses the phrase "on-site power production *facility* with a rated capacity of ten MW or less" (emphasis added). The commission determines that it is the rated capacity of the individual generating unit, not the total capacity available to the customer, which is applicable in this instance. The intent of Legislature was to encourage distributed generation regardless of a customer's size. It is also unlikely that for a big industrial customer it would be economical to install an additional ten-MW unit to serve its load so that it can avoid CTC. Therefore, the commission declines to make the changes proposed by OPC.

OPC also proposed revision of the last sentence in subsection (i)(3) to clarify intent of the sentence. OxyChem replied to OPC's claim that there is a "logical disconnect" between the last sentence in proposed §25.345(i)(3) and §25.345(i)(2). According to OxyChem, the purpose of the sentence identified by OPC is to make it clear that the customer is responsible for paying stranded costs charges associated with the service it actually receives from the utility, such as stand-by.

The commission agrees with OxyChem. The customer whose power is obtained from new on-site generation, but does not have a material reduction in the energy delivered through the T&D utility's facilities must still pay a CTC based on the service it receives from the T&D utility. A customer may not switch to new on-site generation overnight. A CTC reflecting the output of the new on-site generation will be assigned after the materiality threshold is met pursuant to PURA §39.252(b)(2).

Subsection (j) Collection and rate design of CTC charges

Shell stated that class consolidation should not notably disadvantage any particular customer class. TXI noted that its major concern is that commission will mandate consolidation of rate classes. TXI stated its support of the rule the way as proposed, because it does not mandate consolidation and allows a utility by utility approach.

TXI proposed additional language to this subsection to define the term materially disadvantaged as an increase of costs more than 5.0% when compared to the charges without consolidation. TIEC stated that the proposed rule does not fully protect customers from cross-subsidization and proposed an amendment to indicate that no *customer* shall be materially disadvantaged by class consolidation in addition to *customer class.*

The commission disagrees with TXI's and TIEC's suggestion to define a materiality threshold in the rule. The commission determines that impact of class consolidation must be addressed on a utility-by-utility basis. The language in the proposed rule is flexible enough to accomplish that goal and, at the same time, address the commenters' concern.

Nucor proposed additional language to this subsection: (1) to allow billing of CTC charges direct to the retail customer, (2) to reflect different voltage levels of service, (3) to prohibit consolidation of different types interruptible service classes, and (4) to mandate the setting of CTCs on a per-kWh basis. Nucor also proposed a new subsections (k) and (l) in accordance with their comments to Preamble Question Numbers 1, 2, and 3 regarding the test year data and system-wide sharing of benefits of load growth.

The commission disagrees with Nucor and determines that the rules should not include the proposed level of detail with respect to rate design. In accordance with commission decision in Preamble Question Numbers 1, 2, and 3, most of the rate design issues will be addressed on a utility-by-utility basis.

Reliant recommended revising the next to last sentence to provide for no less than five classes and to combine standby and maintenance into a single class. TIEC objected to Reliant's recommendation and stated that standby and maintenance services have distinct characteristics and are priced differently. TIEC recommended using the term "back-up" instead of "standby".

The commission determines that the only rider beside non-firm which is mandated by SB7, is a rate class for the customers who purchase electricity to supplement their new or eligible on-site generation. Each utility may design a rider different than others. Therefore, the commission elects to use the term "back-up", which is intended to encompass standby, maintenance, and back-up power and has amended the proposed rule accordingly.

TXU objected to CU/TLSC/Texas ROSE's recommendation (in answer to Preamble Question Number 4) to revise the language in proposed §25.345(j) to include disclosure to the customer of CTCs. According to TXU, which charges must be reflected on a customer's bill is more appropriately addressed in the customer protection rule making.

The commission agrees with TXU and declines to make changes proposed by CU/TLSC/Texas ROSE.

§25.346. Separation of Electric Utility Metering and Billing Costs and Activities.

Comments over entire section

Enron commented that the proposed section should be approved as published.

Texas CAI and Texas BOMA commented that their associations are concerned about the constitutionality of the rules to the extent that they constitute governmentally compelled access rights by such meter and billing service companies onto private property without due process and compensation.

Under PURA §39.107 (c), the commission finds that the owner of a property must grant reasonable and nondiscriminatory access to transmission and distribution utilities, retail electric providers, electric cooperatives, and municipally owned utilities for metering purposes. While the commission is cognizant of landowner and property rights, where a landlord has separately metered tenanted premises, it is not a taking for the State to prescribe the manner in which reasonable and nondiscriminatory access will be provided to those meters.

Comments on subsection (c)(1)

CSW suggested that this subsection should be clarified to provide that the T&D utility may recover any O&M and capital costs associated with new billing systems, upgrades, or modifications that might be required to accommodate billings to retail electric providers. Shell responded to CSW and stated that the commission should not pre-approve any utility's rate recovery, and if this revision is accepted, the word "prudent" should be added to the suggested language.

The commission finds that CSW's proposed clarification of subsection (c)(1) is unnecessary. T&D utility billing system services as defined in §25.341(24) as proposed allows flexibility to address CSW's concerns in the cost separation proceedings.

Comments on subsection (d)(3)

CSW suggested that in §25.346 (d)(3), the words "embedded cost-based" be deleted from the portion of the rule which states that additional billing services be provided under "commission-approved embedded cost-based tariffs." CSW suggested the deletion because the phrase in question adds potential confusion and is unnecessary as long as the commission approval requirement is present. Further, CSW commented that as long as costs associated with the additional billing services are not included in the basic billing and the additional services are priced at or above marginal cost, the T&D utility should have pricing flexibility for its tariffs. Enron commented that all services provided by a T&D utility, including discretionary services, must be provided under a commission-approved embedded cost-based tariff. In §25.346(d)(3), TXU commented that, given the breadth of services encompassed within the catch-all category "additional billing services," it would be quite burdensome and potentially impractical to achieve with the proposed requirement that *all* such services be provided pursuant to a "commission-approved embedded cost-based tariff." TXU urged the commission to reconsider the burden imposed by this proposed rule provision.

The commission disagrees with the comments of CSW and TXU. To ensure non-discriminatory and transparent pricing, the commission believes that it is essential to price these discretionary services pursuant to embedded cost-based tariffs. In order to address TXU's concern, the commission agrees to eliminate the referenced word "all" so that it is clear that additional billing services do not have to be captured under one single charge (*i.e.*, multiple charges by rate class).

Shell commented that when this paragraph refers to "all additional billing services," the commission should clarify that these services refer to the "additional retail billing services pursuant to PURA §39.107(e)." Shell provided additional language for paragraph (3).

The commission agrees with Shell that additional billing services should refer only to those services referenced under PURA §39.107(e), and modifies subsection (d)(3) accordingly.

The commission also concludes that the definition of additional billing services as defined in §25.341(4) should clearly reflect services in PURA §39.107(e). The commission amends §25.341(4) to that effect.

Comments on subsection (d)(4)

Reliant provided revised language for this subsection in order to allow the T&D utility to directly bill a retail customer for the following: (1) where the customer has dealt directly with a T&D utility for the provision of specific services, such as line extensions, or (2) where it is necessary for the T&D utility to bill a customer directly to collect competition transition charges or transition charges. OPC replied to Reliant's retail billing arguments by stating that the Reliant's arguments directly contradict PURA §39.107(e). TXU commented that proposed §25.346(d)(4) is too restrictive and that the T&D utility should be able to bill customers directly for services such as relocation, addition of customer-requested facilities, or collection for damaged T&D utility facilities. In addition, if the REP defaults in the payment of transition charges to the T&D utility, TXU said that the utility must have the ability to bill and collect transition charges directly from customers. TXI also commented that this paragraph incorrectly prohibits direct retail billing by the T&D utility to end-use customers, except in the case where a REP requests this service and the T&D utility chooses to provide this service. TXI suggested that PURA §39.203(a) authorizes a T&D utility to both provide and bill for T&D services to retail end-users after January 1, 2002. TXI submitted additional language that allows for direct retail billing for transmission and distribution services rendered in accordance with PURA §39.203(a). TIEC supported the proposed language suggested by TXI.

The commission believes that the proposals suggested by Reliant, TXU, TXI, and TIEC would lead to an unnecessary duplication of retail billing systems and increase the non-bypassable charges for the T&D utility. Therefore, the commission rejects the parties' proposed changes. The commission agrees with OPC and finds that PURA §39.107(e) is clear that any direct retail billing services provided by the T&D utility to end-use customers will occur only at the request of a end-use customer's retail electric provider.

Comments on subsection (e)(1)

Shell commented that the commission should not require REPs to incur uncollectible transmission and distribution charges. Because of limited margins associated with residential customers, Shell suggested that the REP only incur bad debts related to its services only and not be forced to cover the business risks both for generation and wires services. Shell further commented that, taken literally, PURA §39.107(d) could mean that the REP must pay whatever charges, however mistakenly calculated, the T&D utility might erroneously bill and the REP could never question the charges. Shell suggested that §39.107(d) only relates to the physical delivery of bills and payment handling in order to avoid the duplication of billing system costs. This section of the statute was never intended to assign substantive liabilities onto the REP. Shell commented that if the commission maintains this paragraph as written, the commission should adopt the following two safeguards: (1) the T&D utility's rates should not contain any bad debt expense; and (2) the REP should possess greater freedom to terminate non-paying customers' service. Enron commented that the T&D utility would only provide service to a limited number of retail customers; therefore, all uncollectibles and customer deposits should be the responsibility of the REP.

The commission agrees with Enron and finds that PURA §39.107(d) mandates that the retail electric provider be responsible for paying the non-bypassable charges incurred by the T&D

utility to serve the retail electric provider's end-use customers. With regard to Shell's comments, the commission concludes that customer uncollectibles and deposits will be assigned to the unregulated function for the cost separation proceedings. With regard to Shell's second safeguard, the commission finds this safeguard more appropriately addressed in Project Number 21080, *Terms and Conditions for Transmission and Distribution Access, Including Tariffs, and Modifications to Existing Transmission Rules*.

CU/TLSC/Texas ROSE commented that the transfer of collections to the REP provides a disincentive to REPs to offer and market power to the low income and economically distressed neighborhoods. CU/TLSC/Texas ROSE further commented that commission rules should promote policies and structures that assure competitive access to customers who are sometimes perceived as difficult to serve. Finally, CU/TLSC/Texas ROSE commented that on the onset of competition, the security deposits held by the T&D utility should be transferred to the customer's REP.

The commission finds that comments of CU/TLSC/Texas ROSE are beyond the scope of this rulemaking and should be addressed within future commission rulemaking projects.

Comments on subsection (e)(2)

Reliant commented that the assignment of the retail customer uncollectibles and deposits to the competitive energy services function implies that the assignment occurs on or before September 1, 2000 (the date in which competitive energy services are to be separated from regulated utility activities). Reliant suggested that retail customer uncollectibles and deposits are part of the integrated utility's cost structure and should stay with the utility during the rate freeze and be reflected in the annual reports filed in accordance with PURA §§39.257–39.259. Reliant provided revised language for paragraph (2).

The commission finds that retail customer uncollectibles and deposits are inappropriately assigned to the competitive energy services function for purposes of cost separation. The commission concludes that retail uncollectibles and deposits should be assigned to the unregulated function as prescribed by proposed §25.344(g)(2)(I). The commission amends subsection (e)(2) accordingly.

Comments on subsection (g)

EGSI suggested that this section should be revised to reflect PURA's explicit direction that metering service and equipment will not be competitive until the dates specified in §39.107. EGSI proposed language which establishes that advanced metering be provided by the T&D utility until the equipment or service becomes competitive pursuant to §39.107.

The commission declines to make EGSI's proposed change because current commission rules properly define the scope of "metering services" as prescribed by PURA §39.107. As discussed under Preamble Question Number 13, the commission disagrees with EGSI's broad interpretation of "metering services" under PURA §39.107.

In response to revisions made under Preamble Question Number 13, the commission concludes that a competitive energy services prohibition statement should be added after paragraph (1)(A) and paragraph (2) to clarify that competitive energy services relating to this section are prohibited. The commission adopts the following language at the end of the first sentence of both provisions, "provided that affected utilities do not engage in the provision of competitive energy services as defined by §25.341(6) of this title (relating to Definitions) and as prescribed by §25.343 of this title (relating to Competitive Energy Services)."

Comments on subsection (g)(1)(B)

EGSI commented that the replacement of the end-use customer's meter with an advanced meter by the T&D utility would be a discretionary service. EGSI suggested that the proposed rule's requirement that this service be priced at incremental cost is consistent with EGSI's recommendation that discretionary services be priced at no lower than incremental cost.

The commission declines to make the proposed changes as suggested by EGSI. In the instance when an advanced meter replaces the standard meter, it is necessary to recognize that the end-use customer is currently charged for the basic meter within the affected utility's base rate charges. Therefore, it is necessary to only charge end-use customer the difference between the cost of the basic meter and the advanced meter. Furthermore, this section of the proposed rule relates to metering services provided by the electric utility before the introduction of customer choice and thus before the introduction of discretionary services.

For clarification, the commission amends the first part of subparagraph (B) to state "When requested by the end-use customer,…." This clarification provides consistency with a similar provision under proposed subsection (g)(2)(A)(ii). The commission makes other revisions to provide consistency with paragraph (1) of this subsection, providing that the affected utility continue to own, operate, and maintain all meters necessary for measurement of energy usage for the calculation of customer charges.

Comments on subsection (g)(2)(A)(ii)

As discussed under subsection (g)(1)(B), EGSI suggested that the rule's requirement that this service be priced at incremental cost is consistent with EGSI's recommendation that discretionary services be priced at no lower than incremental cost.

The commission finds that the pricing in proposed subsection (g)(2)(A)(ii) is appropriate, and declines to make the suggested changes. In the instance when an advanced meter replaces the standard meter, it is necessary to recognize that the retail electric provider will be charged for the standard meter within the T&D system service rate. Therefore, it is necessary to only charge the retail electric provider the difference between the cost of the standard meter and the advanced meter.

As discussed under subsection (g)(1)(B), the commission replaces the word "provided" with "owned, operated, and maintained."

EGSI also proposed new language to address T&D utility cost recovery of additional advanced meters when installed at the request of the REP.

The commission declines to change the paragraph based upon EGSI's recommendation. EGSI's proposal concerns the provision of advanced meters, not merely the replacement of the standard meter as addressed by this subsection. As discussed under Preamble Question Number 13, the commission finds that the customer-premise metering equipment and related services, other than the metering equipment and related services provided by the regulated utility to measure an end-use customer's energy usage for the rendering of a monthly electric bill, constitute competitive energy services and shall be governed by proposed §25.343.

Shell commented that clause (ii) should not give the T&D utility "unbridled discretion" to select the highest cost meter it could find to fulfill a REP's request. Shell recommended two ways of addressing its concern. First, the REP should be able to select the particular advanced meter, as well as the supplier. Second, the commission should limit the costs T&D utilities may assess to prevent them from intentionally over-pricing meters.

The commission declines to adopt Shell's additional recommendations. Under clause (ii), the commission believes that transmission and distribution utilities are expected to make advanced meters available on a non-discriminatory-basis at reasonable prices. The commission also finds that §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates) contains sufficient requirements and safeguards in order to address Shell's concern. If a retail electric provider believes an abuse has occurred, the affected REP may file a complaint at the commission against the offending utility.

Comments on subsection (g)(2)(A)(iii)

TXU commented that PURA §39.157(d)(4) indicates that it is the customer's consent that must be obtained before a utility can release customer information. TXU stated that the authorization request for use of any advanced meter data by this rule provision should have to come from the customer, not from the REP.

The commission declines to adopt TXU's proposed comments. This clause does not affect PURA §39.157(d)(4) in that no release of any proprietary customer information by the utility occurs as a result of this provision. The commission believes that the T&D utility should interface with the retail electric provider for use of any advanced meter data beyond the data needed for the calculation of an end-use customer's electric charges. The commission finds that the clause appropriately requires authorization from the retail electric provider for use of certain advanced meter data since the retail electric provider is being charged the cost for the installation of an advanced meter owned, installed, and maintained by the T&D utility. Under this clause, the commission concludes that the retail electric provider is the proper entity to interface with the end-use customer for obtaining any necessary authorization as may be required by the commission.

TXU and TNMP commented that utilities must have access to the energy usage information needed to prepare system capacity planning and voltage studies. TXU proposed the following language to be added to the end of clause (iii): "and for system capacity planning and voltage studies."

The commission declines to change this clause as suggested by TXU and TNMP. The commission finds that the T&D utility should request authorization of its use from the end-use customer's retail electric provider to obtain and use information subject to clause (iii).

Comments on subsection (g)(2)(A)(iv)

TXU suggested that this provision be revised to make clear that this subsection will not preclude the recovery of the costs of all meters. TXU proposed additional language for incorporation into this subparagraph.

The commission finds that TXU's proposed language is inappropriate for incorporation in the subsection. The commission believes that the recovery of prudent costs for meters in service is properly addressed within a utility's rate proceeding before the commission. Moreover, given the addition of new subsections (g)(1)(B) and (g)(2)(D)(ii) consistent with Preamble Question Number 13, subsection (g)(2)(A)(iv) becomes duplicative and can be deleted.

TNMP commented that the utility should be allowed to install and recover costs for automated meter reading systems where it can be shown that they are a cost-effective alternative to traditional meters and meter reading.

The commission believes that TNMP's concern relates to the provision of standard metering service. It is the utility's obligation to provide T&D services in a prudent, cost-effective fashion; if automated meter reading meets this standard, then it can be accommodated under the proposed rule as published and its costs can be recovered through normal ratemaking proceedings.

Comments on subsection (g)(2)(B)

TXU commented that the REP's accessing of the T&D utility's standard meter should not interfere with the T&D utility's ability to gather data for billing purposes. TXU proposed additional language for incorporation into subparagraph (B).

The commission declines to make the changes proposed by TXU. This subparagraph is intended to be a broad standard, ensuring that a retail electric provider is not precluded from accessing the standard meter. The commission believes that other terms and conditions relating to standard meter access, including TXU's comments, are beyond the scope of this rulemaking. The commission concludes that if terms and conditions for standard meter access are needed, then these issues should be addressed within other commission rulemakings.

Comments on subsection (g)(2)(C)

TNMP commented that if the end-use customer installs a meter down-stream from the standard meter, the rule should clearly state which meter will be used for billing purposes between the REP and the T&D utility.

The commission agrees with TNMP's suggestion for clarification. The standard meter should be the meter used for billing purposes between the REP and the T&D utility. The commission adopts new subsection (g)(2)(A)(ii) as follows: "The transmission and distribution utility shall bill a retail electric provider for non-bypassable charges based upon the measurements obtained from each end-use customer's standard meter."

Comments on subsection (g)(2)(D)(i)

TIEC commented that this section of the rule contains a blanket prohibition on the provision of advanced metering equipment and services by T&D utilities. TIEC suggested that clause (i) be modified to include a grandfather provision for existing advanced metering equipment already installed by incumbent utilities. Such a provision would be consistent with language found in proposed §25.346(g)(2)(A)(iv).

The commission concludes that it is reasonable to exempt metering equipment installed, operated, and maintained by the affected utility consistent with the commission's recommendation under Preamble Question Number 13.

Comments on subsection (g)(2)(D)(iii)

As discussed under subsection (g)(2)(A)(iii), TXU commented that authorization request for use of any advanced meter data under this provision and would have to come from the customer, not from the REP.

As discussed under subsection (g)(2)(A)(iii), the commission declines to incorporate TXU's proposed changes.

Comments on subsection (g)(2)(D)(iv)

In response to the changes adopted under Preamble Question Number 13 and to further clarify the intent of this clause, the commission adds the word "advanced" in front of "metering equipment" in order to ensure consistency with subparagraph (D)(i). The commission adds the word "standard" in front of the word "meter" in order to clarify the "meter" to which the clause refers. The commission also deletes the phrase "or on the transmission and distribution utility's side of the meter" to clarify that this clause should only pertain to advanced metering equipment installed onto the transmission and distribution utility's standard meter. The commission does not intend for this provision to apply to metering equipment on the transmission and distribution utility's side of the standard meter to support transmission and distribution system planning and operations. The commission also reformats the final three lines of this clause.

Comments on subsection (g)(2)(D)(v)

The commission finds that clause (i) of this subparagraph clearly mandates that the transmission and distribution utility does not provide advanced metering equipment or services that are deemed competitive energy services. Under Preamble Question Number 13, the commission also finds that advanced metering equipment is included under new §25.341(6)(V). To reflect the policies of Preamble Question Number 13 and to clarify subparagraph (D)(v) to reflect the commission's intent under clause (i), the commission adds an additional sentence at the end of the clause that states: "Unless authorized by clause (ii) or by the commission, the advanced metering equipment shall not be provided by the transmission and distribution utility."

Comments on subsection (g)(2)(D)(vi)

For clarity and consistency with subparagraph (D), the commission deletes the word "any" and adds the word "advanced." Also, in response to the changes adopted by Preamble Question Number 13 and for reasons discussed under clauses (iv) and (v) of this subparagraph, the commission inserts "provided to the transmission and distribution utility for installation onto the standard meter" after the word "equipment." This clarification is necessary and will ensure that all advanced metering equipment meets contemporaneous industry safety standards and performance codes.

Comments on new subsection (g)(2)(D)(vii)

TXU proposed adding a new clause (vii) to ensure that this section allows the continued use of and recovery of costs for all advanced metering in service at the effective date of this section.

The commission finds that TXU's proposed language is inappropriate; the recovery of *prudent* costs for meters in service should be addressed in a rate proceeding before the commission.

Shell offered to clarify that REPs are not required to provide advanced metering services. Shell also provided new rule language it designated as new clause (vii).

The commission does not find that the proposed rule implicitly mandates that the retail electric provider offer advanced metering services. Therefore, the commission believes that Shell's proposed language is unnecessary, and declines to include it.

For organizational purposes only, the commission moves proposed clause (ii) to the end of this subparagraph. The commission renumbers affected clauses accordingly.

Comments on subsection (h)(1)

Enron commented that the proposed rule should not preclude a third party from access to the utility's meter to provide energy-related services. Enron suggested that this provision remain in the proposed rule as published.

The commission has left this provision intact.

Comments on subsection (i)(2)

TXU suggested that the Legislature intended that the "independent organization," not the commission, establish and enforce transaction settlement procedures (see PURA §39.151(d)). Therefore, TXU proposed that "by the commission" be deleted and replaced with "in accordance with PURA §39.151." In response to TXU's comments, PG&E cited PURA §39.151(d), which states that "an independent organization…shall establish procedures, *consistent with this title and the commission's rules*….*The procedures shall be subject to commission oversight and review*." (Emphasis added). PG&E replied that the language of PURA §39.151 clearly indicates that the commission, not ERCOT, retains primacy in establishing and enforcing settlement procedures.

The commission agrees with PG&E's comments and declines to adopt TXU's proposed changes. The commission, however, has confidence in the work presently being done by the Ad Hoc Committee at ERCOT to develop the procedures, among other things, when ERCOT seeks certification as an Independent Service Operator (ISO) pursuant to PURA §39.151.

Comments on new subsection (i)

TAA commented that PURA §39.107(c) explicitly allows rental property owners to impose reasonable and nondiscriminatory restrictions on electric providers who enter the property for metering purposes at the request of rental tenants. TAA commented that it is common sense that property owners be able to require that service providers working on their property meet certain criteria, such as placing restrictions on reasonable hours that meters could be installed or read. TAA commented that the property owner should not be held liable nor have to bear the cost of damages caused by a power disruption or fire because a meter was improperly installed. TAA further stated that in order to prevent trespassing or criminal activity on a property, the property owner may require contractors or others working on the property to check in at the onsite management office upon arrival or even request contractors to perform criminal background checks on workers on the property to ensure safety of the property owner's tenants or employees. Therefore, TAA proposed a new subsection (i) in order to address its concerns. Texas CAI, Texas BOMA, and Commercial Associations supported this new subsection.

The commission finds that this subsection is beyond the scope of the original proposal and is therefore better addressed in a subsequent rulemaking. The proposal delineates specific terms of access to meters including access by cooperatives and municipal utilities. The commission does not believe there has been a fair opportunity for all interested parties to consider the TAA proposal.

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

These sections are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated (Vernon 1999) (PURA), and Act of May 27, 1999, 76th Legislature, Regular Session (1999), Senate Bill 7, §39 (to be codified at Texas Utilities Code Annotated §§39.001-39.265) (SB7), §§11.002(a), 14.001, 14.002, 14.151, 14.154, 38.021, 38.022, 39.001, 39.051, 39.107, 39.157, 39.201, and 39.251 through 39.265. Section 11.002(a) requires establishment of a comprehensive and adequate regulatory system by the commission to ensure just and reasonable rates, operations, and services. Section 14.001 grants the commission the general power to regulate and supervise the business of each utility within its jurisdiction. Section 14.002 provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction. Section 14.151 grants the commission authority to prescribe the manner of accounting for all business transacted by the utility. Section 14.154 grants the commission limited authority over the utility's affiliates, with respect to their transactions with the utility. Section 38.021 requires that utilities not grant an unreasonable preference to or impose an unreasonable disadvantage on different persons in the same classification. Section 38.022 requires that utilities not discriminate against competitors or engage in practices that restrict or impair competition in the electric market. Section 39.001 states the legislative policy and purpose for a competitive electric power industry. Section 39.051 requires that each electric utility unbundle personnel, information flow, functions, and operations into a power generation company, a retail electric provider, and a transmission and distribution company. Section 39.107 grants the commission authority to adopt provisions regarding the metering and billing services. Section 39.157 grants the commission authority to take actions to address market power and adopt rules and enforcement procedures to govern transactions or activities between utilities and their affiliates. Section 39.201 requires each electric utility to file, on or before, April 1, 2000, proposed tariffs for its proposed transmission and distribution utility. Sections 39.251 through 39.265 grant the commission authority to allow electric utilities to recover stranded costs through a competition transition charge.

Cross Reference to Statutes: Public Utility Regulatory Act §§11.002(a), 14.001, 14.002, 14.151, 14.154, 38.021, 38.022, 39.001, 39.051, 39.107, 39.157, 39.201, and 39.251-39.265.

§25.341. Definitions.

The following words and terms, when used in Division I of this subchapter (relating to Unbundling and Market Power), 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) **Affected utilities** — 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 the Texas Utilities Code, Chapter 184, Subchapter C, 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 the Public Utility Regulatory Act (PURA) §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) this state or an agency of this 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, Chapter 184, Subchapter C.

(3) **Advanced metering** — Includes any metering equipment or services that are not transmission and distribution utility metering system services as defined in this section.

(4) **Additional retail billing services** — Retail billing services necessary for the provision of services as prescribed under PURA §39.107(e) but not included in the definition of transmission and distribution utility billing system services under this section.

(5) **Competition transition charge (CTC)** — Any non-bypassable charge that recovers 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 Effects of Certain Types of Regulation") for generation-related assets if required by the provisions of PURA, Chapter 39. For purposes of PURA §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 PURA §39.262(h), whichever is earlier, and shall include stranded costs incurred under PURA §39.263. Competition transition charges also include the transition charges established pursuant to PURA §39.302(7) unless the context indicates otherwise.

(6) **Competitive energy services** — Customer energy services business activities which are capable of being provided on a competitive basis in the retail market. Examples of competitive energy services include, but are not limited to the marketing, sale, design, construction, installation, or retrofit, financing, operation and maintenance, warranty and repair of, or consulting with respect to:

(A) energy-consuming, customer-premise equipment;

(B) the provision of energy efficiency and control of dispatchable load management services;

(C) the provision of technical assistance relating to any customer-premises process or device that consumes electricity, including energy audits;

(D) customer or facility specific energy efficiency, energy conservation, power quality and reliability equipment and related diagnostic services;

(E) the provision of anything of value other than tariffed services to trade groups, builders, developers, financial institutions, architects and engineers, landlords, and other persons involved in making decisions relating to investments in energy-consuming equipment or buildings on behalf of the ultimate retail electricity customer;

(F) customer-premises transformation equipment, power-generation equipment and related services;

(G) the provision of information relating to customer usage other than as required for the rendering of a monthly electric bill, including electrical pulse service;

(H) communications services related to any energy service not essential for the retail sale of electricity;

(I) home and property security services;

(J) non-roadway, outdoor security lighting, except for the provision of service until January 1, 2002 to customers that were receiving such service on September 1, 2000;

(K) building or facility design and related engineering services, including building shell construction, renovation or improvement, or analysis and design of energy-related industrial processes;

(L) hedging and risk management services;

(M) propane and other energy-based services;

(N) retail marketing, selling, demonstration, and merchant activities;

(O) facilities operations and management;

(P) controls and other premises energy management systems, environmental control systems, and related services;

(Q) premise energy or fuel storage facilities;

(R) performance contracting (commercial, institutional and industrial);

(S) indoor air quality products (including, but not limited to air filtration, electronic and electrostatic filters, and humidifiers);

(T) duct sealing and duct cleaning;

(U) air balancing;

(V) customer-premise metering equipment and related services other than as required for the measurement of electric energy necessary for the rendering of a monthly electric bill; and

(W) other activities identified by the commission.

(7) **Discretionary service** — Service that is related to, but not essential to, the transmission and distribution of electricity from the point of interconnection of a generation source or third-party electric grid facilities, to the point of interconnection with a retail customer or other third party facilities.

(8) **Distribution** — For purposes of §25.344(g)(2)(C) of this title (relating to Cost Separation Proceedings), distribution relates to system and discretionary services associated with facilities below 60 kilovolts necessary to transform and move electricity from the point of interconnection of a generation source or third party electric grid facilities, to the point of interconnection with a retail customer or

other third party facilities, and related processes necessary to perform such transformation and movement. Distribution does not include activities related to transmission and distribution utility billing services, additional billing services, transmission and distribution utility metering services, and transmission and distribution customer services as defined by this section.

(9) **Electronic data interchange** — The computer application to computer application exchange of business information in a standard format.

(10) **Energy service** — As defined in §25.223 of this title (relating to Unbundling of Energy Service).

(11) **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.

(12) **Generation** — For purpose of §25.344(g)(2)(A), generation includes assets, activities and processes necessary and related to the production of electricity for sale. Generation begins with the acquisition of fuels and their conversion to electricity and ends where the generation company's facilities tie into the facilities of the transmission and distribution system.

(13) **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.

(14) **Market value** — For non-nuclear 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 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.

(15) **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 PURA §31.002(6); 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.

(16) **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.

(17) **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.

(18) **Retail stranded costs** — Part of net stranded cost associated with the provision of retail service.

(19) **Standard meter** — The minimum metering device necessary to obtain the billing determinants required by the transmission and distribution utility's tariff schedule to determine an end-use customer's charges for transmission and distribution service.

(20) **Stranded costs** — 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 Effects of Certain Types of Regulation") for generation-related assets if required by the provisions of PURA, Chapter 39. For purposes of PURA §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 PURA §39.262(h), whichever is earlier, and shall include stranded costs incurred under PURA §39.263.

(21) **Stranded Cost Charges** — Competition transition charges as defined in this section and transition charges established pursuant to PURA §39.302(7).

(22) **System service** — Service that is essential to the transmission and distribution of electricity from the point of interconnection of a generation source or third-party electric grid facility, to the point of interconnection with a retail customer or other third party facility. System services include, but are not limited to, the following:

(A) the regulation and control of electricity in the transmission and distribution system;

(B) planning, design, construction, operation, maintenance, repair, retirement, or replacement of transmission and distribution facilities, equipment, and protective devices;

(C) transmission and distribution system voltage and power continuity;

(D) response to electric delivery problems, including outages, interruptions, and voltage variations, and restoration of service in a timely manner;

(E) commission-approved public education and safety communication activities specific to transmission and distribution that do not preferentially benefit the utility's affiliate(s);

(F) transmission and distribution utility standard metering and billing services as defined by this section;

(G) commission-approved administration of energy savings incentive programs in a market-neutral, nondiscriminatory manner, through standard offer programs or limited, targeted market transformation programs, and

(H) line safety, including tree trimming.

(23) **Transmission** — For purposes of §25.344(g)(2)(B) of this title, transmission relates to system and discretionary services associated with facilities at or above 60 kilovolts necessary to transform and move electricity from the point of interconnection of a generation source or third party electric grid facilities, to the point of interconnection with distribution, retail customer or other third party facilities, and related processes necessary to perform such transformation and movement. Transmission does not include activities related to transmission and distribution utility billing system services, additional billing services, transmission

and distribution utility metering system services, and transmission and distribution utility customer services as defined by this section.

(24) **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 PURA §31.002(6), in a qualifying power region certified under PURA §39.152, but does not include a municipally owned utility or an electric cooperative.

(25) **Transmission and distribution utility billing system services —** Services related to the production and remittance of a bill to a retail electric provider for the transmission and distribution charges applicable to the retail electric provider's customers as prescribed by PURA §39.107(d), and billing for wholesale transmission service to entities that qualify for such service. Transmission and distribution utility billing system services may include, but are not limited to, the following:

(A) generation of billing charges by application of rates to customer's meter readings, as applicable;

(B) presentation of charges to retail electric providers for the actual services provided and the rendering of bills;

(C) extension of credit to and collection of payments from retail electric providers;

(D) disbursement of funds collected;

(E) customer account data management;

(F) customer care and call center activities related to billing inquiries from retail electric providers;

(G) administrative activities necessary to maintain retail electric provider billing accounts;

(H) an operating billing system, and;

(I) error investigation and resolution.

(26) **Transmission and distribution utility customer service —** For purposes of §25.344(g)(2)(G) of this title, transmission and distribution customer service relates to system and discretionary services associated with the utility's energy efficiency programs, demand-side management programs, public safety advertising, tariff administration, economic development programs, community support, advertising, customer education activities, and any other customer services.

(27) **Transmission and distribution utility metering system services —** Services that relate to the installation, maintenance, and polling of an end-use customer's standard meter. Transmission and distribution utility metering system services may include, but are not limited to, the following:

(A) ownership of standard meter equipment and meter parts;

(B) storage of standard meters and meter parts not in service;

(C) measurement or estimation of the electricity consumed or demanded by a retail electric consumer during a specified period limited to the customer usage necessary for the rendering of a monthly electric bill;

(D) meter calibration and testing;

(E) meter reading, including non-interval, interval, and remote meter reading;

(F) individual customer outage detection and usage monitoring;

(G) theft detection and prevention;

(H) customer account maintenance;

(I) installation or removal of metering equipment;

(J) an operating metering system, and;

(K) error investigation and re-reads.

§25.342. Electric Business Separation.

(a) **Purpose.** The purpose of this section is to identify the competitive electric industry business activities that must be separated from the regulated transmission and distribution utility and performed by a power generation company (PGC), a retail electric provider (REP), or some other business unit pursuant to the Public Utility Regulatory Act (PURA) §39.051. This section establishes procedures for the separation of such business activities.

(b) **Application.** This section shall apply to affected utilities.

(c) **Compliance and timing.**

(1) Electric utilities must file a business separation plan on or before January 10, 2000, pursuant to PURA §39.051(e).

(2) Notwithstanding any other provision in this section, an electric utility not subject to this section until the expiration of the exemption set forth in PURA §39.102(c), must file a business separation plan on or before 260 days prior to the expiration of the exemption. Notwithstanding any other provision in this section, on or before the expiration of the exemption set forth in PURA §39.102(c), such an electric utility shall separate from its regulated utility activities its customer energy services business activities and shall separate its business activities from one another into the three units described in subsection (d)(2) of this section.

(3) Upon review of the filing, the commission shall adopt the electric utility's plan for business separation, adopt the plan with changes, or reject the plan and require the electric utility to file a new plan.

(d) **Business separation.**

(1) An electric utility may not offer competitive energy services after September 1, 2000; however, an electric utility may petition the commission pursuant to §25.343(d) of this title (relating to Competitive Energy Services) for authority to provide to its Texas customers or some subset of its customers any service otherwise identified as a competitive energy service.

(2) Not later than January 1, 2002, each electric utility shall separate its business activities and related costs into the following units: power generation company; retail electric provider; and transmission and distribution utility company. An electric utility may accomplish this separation either through the creation of separate nonaffiliated companies or separate affiliated companies owned by a common holding company or through the sale of assets to a third party. An electric utility may create separate transmission utility and distribution utility companies.

(3) Each electric utility, subject to PURA §39.157(d), shall comply with this section in a manner that provides for a separation of personnel, information flow, functions, and operations, consistent with PURA §39.157(d) and §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates).

(4) All transfers of assets and liabilities to separate affiliated or nonaffiliated companies, a power generation company, retail electric provider, or a transmission and distribution utility company during the initial business separation process shall be recorded at book value.

(e) **Business separation plans.** On or before January 10, 2000, each electric utility subject to PURA §39.051(e) shall file a business separation plan with the commission according to a commission-approved Business Separation Plan Filing Package (BSP-FP).

(1) The business separation plan shall include, but shall not be limited to, the following:

(A) A description of the financial and legal aspects of the business separation, the functional and operational separations, physical separation, information systems separation, asset transfers during the initial unbundling, separation of books and records, and compliance with §25.272 of this title both during and after the transition period.

(B) A description of all services provided by the corporate support services company, as well as any corporate support services provided by another separate affiliate including pricing methodologies.

(C) A proposed internal code of conduct that addresses the requirements in §25.272 of this title and the spirit and intent of PURA §39.157. The internal code of conduct shall address each provision of §25.272 of this title, and shall provide detailed rules and procedures, including employee training, enforcement, and provisions for penalties for violations of the internal code of conduct.

(D) A description of each competitive energy service provided within Texas by the electric utility, including a detailed plan for completely and fully separating these competitive energy services on or before September 1, 2000, as set forth in §25.343 of this title.

(E) Descriptions of all system services, discretionary services, and other services pursuant to subsection (f) of this section to be provided within Texas by the transmission and distribution utility.

(2) To the extent that not all of the detailed information required to be filed on January 10, 2000 is available, the electric utility shall provide a firm schedule for

supplemental filings. The commission shall approve only portions of the business separation plan for which complete information is provided.

(f) **Separation of transmission and distribution utility services.**

(1) **Classification of services.** Each service offered, or potentially offered, by a transmission and distribution utility shall be classified as one of the following:

(A) **System service.** The costs associated with providing system service are system-wide costs which are borne by the retail electric provider serving all transmission and distribution customers.

(B) **Discretionary service.**

(i) The cost associated with each discretionary service is customer-specific and should be borne only by the retail electric provider serving the transmission and distribution customer who purchases the discretionary service.

(ii) Each discretionary service shall be provided by the transmission and distribution utility on a nondiscriminatory basis pursuant to a commission-approved embedded cost-based tariff.

(iii) The costs associated with providing discretionary services are tracked separately from costs associated with providing system services.

(iv) A discretionary service is not a competitive energy service as defined by §25.341(6) of this title (relating to Definitions).

(C) **Petitioned service.** Service in which a petition to provide a specific competitive energy service has been granted by the commission pursuant to §25.343(d)(1) of this title.

(D) **Other service.**

(i) The offering of any other services shall be limited to those services which:

(I) maximize the value of transmission and distribution system service facilities; and

(II) are provided without additional personnel and facilities other than those essential to the provision of transmission and distribution system services.

(ii) If the transmission and distribution utility offers a service under clause (i) of this subparagraph, the transmission and distribution utility shall:

(I) track revenues and to the extent possible the costs for each service separately;

(II) offer the service on a non-discriminatory-basis, and if the commission determines that it is appropriate, pursuant to a commission-approved tariff, and;

(III) credit all revenues received from the offering of this service during the test year after known and measurable adjustments are made to lower the revenue requirement of the transmission and distribution utility on which the rates are based.

(2) **Competitive energy services**. A transmission and distribution utility shall not provide competitive energy services as defined by §25.341(6) of this title (relating to Definitions) except as permitted pursuant to §25.343(d)(1) of this title.

§25.343. Competitive Energy Services.

(a) **Purpose.** The purpose of this section is to identify all competitive energy services which shall not be provided by affected utilities after September 1, 2000.

(b) **Application.** This section applies to electric utilities as defined by the Public Utility Regulatory Act (PURA) §31.002(6) and transmission and distribution utilities as defined by PURA §31.002(19) that provide service in Texas. This section does not apply to municipally owned utilities or electric cooperatives. This section shall not apply to an electric utility under PURA §39.102(c) until the termination of its rate freeze period.

(c) **Competitive energy service separation.** Affected utilities shall not provide competitive energy services after September 1, 2000 except for the administration of energy efficiency programs as specifically provided elsewhere in this chapter.

(d) **Petitions relating to the provision of competitive energy services.**

(1) **Petition by an affected utility to provide a competitive energy service.** A utility may petition the commission to provide on an unbundled tariffed basis a competitive energy service which is not widely available to customers in an area. The utility has the burden to prove to the commission that the service is not widely available in an area.

(A) **Review of petition.** In reviewing an affected utility's petition to provide a competitive energy service, the commission may consider, but is not limited to, the following:

(i) geographic and demographic factors;

(ii) number of vendors providing a similar or closely-related competitive energy service in the area;

(iii) whether an affiliate of the affected utility offers a similar or closely-related competitive energy service in the area;

(iv) whether the approval of the petition would create or perpetuate a market barrier to entry for new providers of the competitive energy service.

(B) **Petition deemed approved.** A petition shall be deemed approved without further commission action on the effective date specified in the petition if no objection to the petition is filed with the commission and adequate notice has been completed at least thirty days prior to the effective date. The specified effective date must be at least sixty days after the date the petition is filed with the commission. Notice shall be provided through a newspaper publication once a week for two consecutive weeks in a newspaper in general circulation throughout the service area for which the petition is requested. Such newspaper notice shall state in plain language:

(i) the purpose of the petition;

(ii) the competitive energy service that is the subject of the petition; and

(iii) the date on which the petition will be deemed approved if no objection is filed with the commission.

(C) **Approval of petition.**

(i) If a petition under this paragraph is granted, the utility shall provide the petitioned service pursuant to a fully unbundled, embedded cost-based tariff.

(ii) The utility's petition to offer the competitive energy service terminates two years from the date the petition is granted by the commission, unless the commission approves a new petition from the utility to continue providing the competitive energy service.

(iii) The costs associated with providing this service shall be tracked separately from other transmission and distribution utility costs.

(2) **Petition to classify a service as a competitive energy service or to end the designation of a competitive energy service as a petitioned service.** An affected person or the Office of Regulatory Affairs may petition the commission to classify a service as a competitive energy service or to end the designation of a competitive energy service as a petitioned service. The commission may

consider, but is not limited to, the factors pursuant to paragraph (1) of this subsection (where applicable) when reviewing a petition under this paragraph.

(e) **Filing requirements.**

(1) Affected utilities shall file the following as part of their business separation plans pursuant to §25.342 of this title (relating to Electric Business Separation):

(A) descriptions of each competitive energy service provided by the utility;

(B) detailed plans for completely and fully separating competitive energy services; and

(C) petitions, if any, with associated unbundled tariffs to provide a competitive energy service(s) pursuant to subsection (d)(1) of this section. As part of this filing, affected utilities shall provide all supporting workpapers and documents used in the calculation of the charges for the petitioned services.

(2) Affected utilities shall file complete cost information related to paragraph (1) of this subsection pursuant to §25.344 of this title (relating to Cost Separation Proceedings) and the Unbundled Cost of Service Rate Filing Package (UCOS-RFP).

§25.344. Cost Separation Proceedings.

(a) **Purpose.** The purpose of this section is to establish the procedure by which affected utilities will comply with the Public Utility Regulatory Act (PURA) §39.201.

(b) **Application.** This section shall apply to all utilities subject to PURA §39.201.

(c) **Compliance and timing.**

(1) All electric utilities must file a cost separation case under this section on or before April 1, 2000 according to a unbundled cost of service rate filing package (UCOS-RFP) approved by the commission. Each electric utility shall, in its cost separation filing, file proposed tariffs for its proposed transmission and distribution utility. The filings shall include supporting cost data for the determination of the utility's non-bypassable delivery charges, which shall be the sum of transmission charges, distribution charges, metering system service charges, billing system service charges, customer service system charges (if any), municipal franchise charges, nuclear decommissioning charges (if any), a competition transition charge (if any), and a system benefit fund fee.

(2) Notwithstanding any other provision in this section, an electric utility not subject to this section until the expiration of the exemption set forth in PURA §39.102(c), must file its cost separation case on or before 170 days prior to the expiration of the exemption.

(d) **Test year.** A historic test year shall be used to determine a forecast test year, defined as follows:

(1) **Historic year –** for utilities filing a cost separation case on or before April 1, 2000, the historic year shall be the 12-month period ended September 30, 1999. For a utility filing a cost separation case after April 1, 2000, the historic year shall be a 12-month period deemed reasonable by the commission.

(2) **Forecast year –** for utilities filing a cost separation case on or before April 1, 2000, the forecast year shall be the projected 12-month period ended December 31, 2002. For a utility filing a cost separation case after April 1, 2000, the forecast year shall be a 12-month period deemed reasonable by the commission.

(e) **Rate of return.** Each electric utility shall file a rate of return that is based on its weighted average cost of capital as determined by one of the alternative methods indicated in the Unbundled Cost of Service Rate Filing Package (UCOS-RFP) approved by the commission.

(f) **System benefit fund fee.**

(1) The system benefit fund fee will be established and implemented by the commission as described in PURA §39.901 and §39.903.

(2) Each utility shall identify the historic year costs associated with a reduced rate for low-income customers, targeted energy efficiency programs for low-income customers, customer education programs, and the property taxes paid to school districts. Total costs will be reported in the unbundled cost of service studies as a

separate line item (or subaccount) in each account where such costs occur. In the forecasting process, historic year costs shall be adjusted to account for future recovery of costs for these expenses through the system benefit fee rather than rates.

(3) System benefit fund costs shall include costs for the following:

(A) A low income rate for firm service which is lower than the regular residential rate and which is exclusively made available to customers whose household income is not more than 125% of the federal poverty guidelines and/or customers who receive food stamps from the Texas Department of Human Services or medical assistance from a state agency administering a part of the medical assistance program.

(B) Low-income energy efficiency programs administered by the Texas Department of Housing and Community Affairs in coordination with existing weatherization programs.

(C) Customer education programs developed pursuant to PURA §39.902.

(D) Estimates of the amount of property tax payments that will be lost by school districts statewide because of electric utility restructuring.

(E) Any other item allowed by law.

(4) The amount of the system benefit fund fee shall be set by the commission pursuant to PURA §39.903(b). Utilities should make initial filings under this rule assuming that the system benefit fund fee will equal $ .50 per MWh.

(g) **Separation of affiliate costs and functional cost separation.**

(1) **Affiliate costs.**

(A) **Separation of affiliate costs.** The affiliate schedules accompanying the UCOS-RFP shall provide sufficient detail to enable the commission to evaluate the necessity and reasonableness of the affiliate expenses and the "no higher than" cost provisions of PURA §36.058 (relating to Consideration of Payment to Affiliate); §25.272 of this title (relating to Code of Conduct for Electric Utilities and Their Affiliates); and §25.273 of this title (relating to Contracts Between Electric Utilities and Their Affiliates). The schedules shall provide the net total amount of affiliate expense requested for each of the historic and forecast years. This information shall be provided by class of items for all affiliate transactions between the transmission and distribution utility and its affiliates including the affiliated power generation company and the affiliated retail electric provider.

(B) **Affiliated service company.** If there is an affiliated service company providing support to the regulated transmission and distribution utility and the other affiliates, then the UCOS-RFP shall include the transactions between the service company, the regulated transmission and distribution utility, the power generation company, the retail electric provider, and all the other affiliates pursuant to PURA §14.154. The UCOS-RFP shall include detailed information on allocation formulas as defined by the reporting schedules.

(C) **Compliance with affiliate rules.** The affiliate transactions reported in the UCOS-RFP shall comply with the code of conduct rules as promulgated in §§25.84 of this title (relating to Annual Reporting of Affiliate Transactions for Electric Utilities), 25.272 of this title, and 25.273 of this title.

(2) **Functional cost separation.** All electric utilities shall separate their costs into nine categories, relating to the following functions, as defined by §25.341 of this title (relating to Definitions):

(A) generation;

(B) transmission;

(C) distribution;

(D) transmission and distribution utility metering system services;

(E) transmission and distribution utility billing system services;

(F) additional retail billing services;

(G) transmission and distribution utility customer service;

(H) competitive energy service; and

(I) other unregulated services.

(3) **Method of cost separation.** Costs shall be assigned to the nine functions using the following three-tier process. No common costs shall be assigned to regulated functions by default. If the utility cannot meet its burden of proof, the costs in question shall be assigned to competitive functions.

(A) For each Federal Energy Regulatory Commission (FERC) account, costs shall be directly assigned to functions to the extent possible, and all relevant workpapers provided.

(B) The utility shall provide detailed workpapers documenting the nature of any costs that cannot be directly assigned. For adequately documented costs, the utility may derive an account-specific functionalization factor based on the directly assigned costs or appropriate cost causation principles. The utility must justify the assignment of common costs to regulated functions, and must present evidence to support any such assignment.

(C) If adequately documented costs remain for which direct assignment or account-specific functionalization cannot be identified, an appropriate functionalization factor as described in the UCOS-RFP may be used. These functionalization factors should only be used as a last resort. If a utility deems a functionalization factor other than the functionalization factor prescribed in the UCOS-RFP to be necessary, the utility shall provide a detailed justification for the chosen functionalization factor.

(h) **Jurisdiction and Texas retail class allocation.** Allocation of each of the functions comprising the transmission and distribution system services revenue requirement to the existing rate classes shall be based on forecasted 2002 test year load data. Costs related to other functions may be allocated based on a test year ending September 30, 1999.

(1) **Jurisdictional allocation.** Functionalized total company costs for the forecast year shall be allocated to the Texas retail jurisdiction. Jurisdictional allocators shall be based on either the methodology approved the Federal Energy Regulatory Commission (FERC), or the methodology used in the last commission-approved cost of service study.

(2) **Texas retail class allocation.** Total Texas retail jurisdiction costs for each of the nine categories shall be allocated among existing rate classes. Consolidation of classes shall be done only during the rate design process.

(A) **Transmission revenue requirement (system services).** Electric Reliability Council of Texas (ERCOT) utilities shall allocate the total transmission revenue requirement based on the average of the four coincident peaks for each existing rate class at the time of ERCOT peak, if that data is available. If that data is not available, the utility may use the average of the four coincident peaks for each existing rate class at the time of the transmission and distribution utility's system peak.. Non-ERCOT utilities shall allocate transmission revenue requirement based on either the FERC-approved methodology or the methodology approved in the last commission-approved cost of service study.

(B) **Distribution revenue requirement (system services).** Costs purely related to demand or customers shall be allocated based on the methodology used in the last cost of service study unless otherwise determined by the commission. Other costs shall be allocated based on allocators analogous to those used during the functionalization process, or appropriate cost-causation principles.

(C) **Generation costs.** Total generation costs shall be allocated to the existing rate classes based on the methodology used to allocate generation costs in the last cost of service study.

(D) **Retail electric provider costs.** Total costs of services which will be provided by the retail electric provider as approved in the business separation plan shall be allocated among classes based on the allocators used in the last cost of service study.

(E) **Decommissioning costs.** Costs associated with nuclear decommissioning obligations shall be allocated based on the methodology used in the last cost of service study unless otherwise approved by the commission. Total costs shall be reported in the unbundled cost of service studies as a separate line item (or subaccount) in each account where such costs occur.

(F) **System Benefit Fund (SBF) Fee**. The SBF fee shall be allocated among customers based on the customer's actual kilowatt-hours used, as measured at the meter and adjusted for voltage level losses.

(i) **Determination of ERCOT and Non-ERCOT transmission costs.**

(1) **ERCOT transmission costs.**

(A) The transmission cost of service for an electric utility in ERCOT shall be as described in §25.192(b) of this title (relating to Transmission Service Rates).

(B) The UCOS-RFP adopted by the commission for the cost separation filings shall be used by the electric utilities filing under this section.

(C) Any redirection of transmission depreciation expense to production by a electric utility in ERCOT pursuant to PURA §39.256 should not affect the utility's wholesale transmission cost of service that is used for determining the ERCOT postage stamp rate.

(2) **Non-ERCOT transmission costs.** For an electric utility in Texas operating outside ERCOT, the utility's open access transmission tariff approved by FERC will be used to determine the utility's transmission cost and rates in Texas.

(j) **Rate design.** Utilities shall consolidate existing rate classes into the minimum number of classes needed to recognize differences in usage of the transmission and distribution systems. Class consolidation shall not materially disadvantage any customer class.

§25.345. Recovery of Stranded Costs Through Competition Transition Charge (CTC).

(a) **Purpose.** The purpose of this section is to establish the rules, regulations and procedures by which affected utilities will comply with Public Utility Regulatory Act (PURA), Chapter 39, Subchapter F relating to Recovery of Stranded Costs Through Competition Transition Charge, PURA §39.201, relating to Cost of Service Tariffs and Charges, and PURA, Chapter 39, Subchapter G relating to Securitization in order to establish a competition transition charge (CTC) as a non-bypassable charge.

(b) **Application.** This section shall apply to all electric utilities as defined in PURA §31.002 which have stranded costs as described in PURA §39.251.

(c) **Definitions.** As used in this section, the following terms have the following meanings unless the context clearly indicates otherwise:

(1) **New on-site generation** — Electric generation capacity greater than ten megawatts capable of being lawfully delivered to the site without use of utility distribution or transmission facilities, which was not, on or before December 31, 1999, either:

(A) A fully operational facility, or

(B) A project supported by substantially complete filings for all necessary site-specific environmental permits under the rules of the Texas Natural Resource Conservation Commission (TNRCC) in effect at the time of filing.

(2) **Eligible generation** — Any electric generation facility that falls into one or more of the following categories:

(A) A fully operational qualifying facility that lawfully served a retail customer's load before September 1, 2001, and for which substantially complete filings were made on or before December 31, 1999, for all necessary site-specific environmental permits under the rules of the TNRCC in effect at the time of filing, so long as such facility serves the same end-user it was serving on September 1, 2001.

(B) An on-site power production facility with a rated capacity of ten megawatts or less;

(C) Any generation facility that lawfully served a retail customer's actual load which is capable of lawfully delivering power to the site without use of utility distribution or transmission facilities and which is not new on-site generation including but not limited to facilities described in subparagraphs (A) and (B) of this paragraph, so long as the facility continues to serve the same end-user or users it was serving on December 31, 1999 if it was fully operational at that time or the end-user or users who first took power from the facility when it became operational if it become operational after December 31, 1999.

(d) **Right to recover stranded costs.** An electric utility is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service. Recovery of retail stranded costs by an electric utility shall be from all existing or future retail customers, including the facilities, premises, and loads of those retail customers, within the utility's geographical certificated service area as it existed on May 1, 1999. A retail customer may not avoid stranded cost recovery charges by switching to on-site generation except as provided by subsection (i) of this section. In multiply certificated areas, a retail customer may not avoid stranded cost recovery charges by switching to another electric utility, electric cooperative, or municipally owned utility after May 1, 1999.

(e) **Recovery of stranded cost from wholesale customers**. Nothing in this section shall alter the rights of utilities to recover wholesale stranded costs from wholesale customers. If the utility decides not to recover some or all stranded costs from its wholesale customers, it shall not recover these costs from retail customers through non-bypassable charges or otherwise.

(f) **Quantification of stranded costs.** An electric utility seeking to recover its stranded costs shall submit the necessary information in compliance with the unbundled cost of service rate filing package (UCOS-RFP) approved by the commission.

(g) **Recovery of stranded costs through securitization.** An electric utility that seeks to recover regulatory assets and stranded costs through securitization financing pursuant to PURA, Chapter 39, Subchapter G shall request a separate competition transition charge for that purpose.

(1) An electric utility that seeks to securitize its regulatory assets or stranded costs pursuant to PURA §39.201(i)(1) shall file an application using the commission-approved form.

(2) An electric utility may seek to securitize its regulatory assets under PURA §39.201(i) any time after September 1, 1999.

(3) An electric utility that seeks to securitize its stranded costs under PURA §39.201(i) must obtain a determination by the commission of its revised estimate of stranded costs prior to submitting its application.

(4) The amount of regulatory assets eligible for securitization as determined by the commission in a proceeding pursuant to §39.201(i)(1) shall be considered in the quantification of stranded costs in subsection (f) of this section.

(h) **Allocation of stranded costs**. Allocation of stranded costs and calculation of CTC per customer class shall be part of the cost separation proceedings as defined in §25.344 of this title (relating to Cost Separation Proceedings). The utility shall submit information in accordance with the instructions contained in the UCOS-RFP.

(1) **Jurisdictional allocation**. Costs shall be allocated to the Texas retail jurisdiction in accordance with the jurisdictional allocation methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(2) **Allocation among Texas customer classes**. Stranded costs shall be allocated in the following manner.

(A) Any capital costs incurred by an electric utility to improve air quality under PURA §39.263 or §39.264 that are included in a utility's invested capital in accordance with those sections shall be allocated among customer classes as follows: 50% of those costs shall be allocated in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design; and the remainder shall be allocated on the basis of the energy consumption of the customer classes.

(B) All other retail stranded costs shall be allocated among retail customer classes in the following manner:

(i) The allocation to the residential class shall be determined by allocating to all customer classes 50% of the stranded costs in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design and allocating the remainder of the stranded costs on the basis of the energy consumption of the classes.

(ii) After the allocation to the residential class required by clause (i) of this subparagraph has been calculated, the remaining stranded costs shall be allocated to the remaining customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design. Non-firm industrial customers shall be allocated stranded costs equal to 150% of the amount allocated to that class.

(iii) After the allocation to the residential class required by clause (i) of this subparagraph and the allocation to the nonfirm industrial class required by clause (ii) of this subparagraph have been calculated, the remaining stranded costs shall be allocated to the remaining customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(iv) Notwithstanding any other provision of this section, to the extent that the total retail stranded costs, including regulatory assets, of investor-owned utilities exceed $5 billion on a statewide basis, any stranded costs in excess of $5 billion shall be allocated among retail customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(v) The energy consumption of the customer classes used in subparagraph (A) of this paragraph and clause (i) of this subparagraph shall be based on the data for the test year ending May 1, 1999 adjusted only for line losses and weather.

(vi) For the rate classes which were not treated as a separate class in the utility's last cost of service study, the generation portion of the base revenues shall be used to develop a demand allocator. For the rate classes that have been determined as discounted rate schedules by the commission, the base revenues used to determine the demand allocator for these rate classes should include imputed revenue.

(i) **Applicability of CTC to customers receiving power from new on-site generation or eligible generation.** A retail customer receiving power from new on-site generation or eligible generation to serve its internal electrical requirements may not avoid payment of stranded costs except as provided in this subsection. A customer's responsibility for payment of stranded costs shall be determined as follows:

(1) **No CTC**. An end-user whose actual load is lawfully served by eligible generation and who does not receive any electrical service that requires the delivery of power through the facilities of a transmission and distribution utility is not responsible for payment of any stranded cost charges.

(2) **CTC for eligible generation.** A retail customer whose actual load is lawfully served by eligible generation who also receives electrical service that requires the delivery of power through the facilities of a transmission and distribution utility shall be responsible for payment of stranded cost charges based solely on the services that are actually provided by the transmission and distribution utility, if any, to the customer after the eligible generation facility became fully operational, such as delivery of supplemental, standby, or backup service. Such charges may not include any costs associated with the service that the customer was receiving from the electric utility or its affiliated transmission and distribution utility under their tariffs before the operation of the eligible generation. A customer who changes the type of service received from the electric utility or its affiliated transmission and distribution utility after the customer commences taking energy from eligible generation will pay stranded cost charges associated with the service it is actually receiving from the transmission and distribution utility.

(3) **CTC for new on-site generation.** A retail customer who commences taking power from new on-site generation that represents a material reduction in the

customer's use of energy delivered through the utility's facilities shall be responsible for payment of stranded cost charges that are calculated by multiplying the output of the new on-site generation utilized to meet the internal electrical requirements of the customer each month by the sum of the applicable stranded cost charges in effect for that month. The applicable CTC for such customer shall be the CTC associated with the service that the customer was receiving from the electric utility prior to switching to new on-site generation. These stranded cost charges shall be paid in addition to the stranded cost charges applicable to energy actually delivered to the customer through the transmission and distribution utility's facilities. A customer who commences taking power from new on-site generation that does not represent a material reduction in the customer's use of energy delivered through the transmission and distribution utility's facilities shall pay the CTC calculated as set forth in paragraph (2) of this subsection for that portion of the customer's load served by the new on-site generation.

(4) **Material reduction.** For purposes of this subsection, a material reduction shall be a reduction of 12.5% or more of the retail customer's use of energy delivered through the utility's transmission and distribution facilities. The reduction shall be calculated by comparing the customer's monthly use of energy attributable to new on-site generation to the customer's average monthly use of energy delivered through the utility's facilities for the 12-month period immediately preceding the date on which the customer commenced taking energy from the new on-site generation.

(5) **Multiple on-site power production facilities.** A retail customer may designate any number of on-site power production facilities located on a single site as eligible generation under subsection (c)(2)(B) of this section as long as the sum of rated capacities of such facilities does not exceed ten megawatts. Stranded cost charges for any on-site power production facility with a rated capacity of ten megawatts or less, not designated as eligible generation under this paragraph, shall be calculated in accordance with the methodology set forth in paragraph (3) of this subsection for new-on-site generation that results in a material reduction in the retail customer's use of energy delivered through the utility's transmission and distribution facilities. For purposes of determining whether the installation of multiple on-site power production facilities under this paragraph has caused a material reduction in the customer's use of energy under paragraph (4) of this subsection, all of the energy delivered to the customer from such facilities will be taken into account. A customer may not create separate entities on a single site for the purpose of gaining exemptions under this paragraph. A retail customer may change the designation of such an on-site power production facility**:**

(A) No sooner than one year after the facility's initial designation;

(B) No sooner than one year after the facility's subsequent designation; or

(C) Upon addition or retirement of any such on-site power production facility being used to serve the customer's load.

(6) **Reporting requirements.** Persons owning or operating new on-site generation or eligible on-site generation shall submit the information required by §25.105 of this title (relating to Registration and Reporting by Power Marketers, Exempt

Wholesale Generators, and Qualifying Facilities). Those persons shall also comply with procedures and reporting requirements described in the transmission and distribution utility's tariffs related to the assignment and collection of the CTC from eligible and new on-site generation and any other commission rule or regulation related to the implementation of this section.

(7) **Adjustment to overall CTC.** On and after January 1, 2005, the commission will periodically review the overall allocation of the CTC among customers and/or customer classes to incorporate the loss of contribution due to customers taking advantage of the specific statutorily granted exceptions under this section and adjust the charges prospectively. To the extent these are known and measurable at the time of the April 2000 filing, sufficient information shall be provided by the filing utility to allow for calculation of the CTC.

(j) **Collection and rate design of CTC charges**. These charges shall be billed to a customer's retail electric provider. The CTC shall recover the amount of stranded costs as defined in PURA, Chapter 39, Subchapter F that are reasonably projected to exist on the last day of the freeze period. Utilities shall consolidate existing rate classes into the minimum number of classes needed to sufficiently recognize differences in usage of the underlying generation assets. Customers shall be classified into no fewer than the following classes: Residential, Commercial, Firm Industrial, Non-firm, and Back-up Service. No customer classes shall be materially disadvantaged by class consolidation.

§25.346. Separation of Electric Utility Metering and Billing Service Costs and Activities.

(a) **Purpose.** The purpose of this section is to identify and separate electric utility metering and billing service activities and costs for the purposes of unbundling.

(b) **Application.** This section shall apply to electric utilities as defined in Public Utility Regulatory Act (PURA) §31.002. This section shall not apply to an electric utility under PURA §39.102(c) until the termination of its rate freeze period.

(c) **Separation of transmission and distribution utility billing system service costs.**

(1) Transmission and distribution billing system services shall include costs related to the billing services described in §25.341(25) of this title (relating to Definitions).

(2) Charges for transmission and distribution billing system services shall not include any additional capital costs, operation and maintenance expenses, and any other expenses associated with billing services as prescribed by PURA §39.107(e).

(d) **Separation of transmission and distribution utility billing system service activities.**

(1) Transmission and distribution utility billing system services as described in §25.341(25) of this title shall be provided by the transmission and distribution utility.

(2) The transmission and distribution utility may provide additional retail billing services pursuant to PURA §39.107(e).

(3) Additional retail billing services pursuant to PURA §39.107(e) shall be provided on an unbundled discretionary basis pursuant to a commission-approved embedded cost-based tariff.

(4) The transmission and distribution utility may not directly bill an end-use retail customer for services that the transmission and distribution utility provides except when the billing is incidental to providing retail billing services at the request of a retail electric provider pursuant to PURA §39.107(e).

(e) **Uncollectibles and Customer Deposits.**

(1) The retail electric provider is responsible for retail customer uncollectibles and deposits.

(2) For the purposes of functional cost separation in §25.344 of this title (relating to Cost Separation Proceedings), retail customer uncollectibles and deposits shall be assigned to the unregulated function, as prescribed by §25.344(g)(2)(I) of this title.

(f) **Separation of transmission and distribution utility metering system service costs.** Transmission and distribution utility metering system services shall include costs related to the metering services as defined in §25.341(27) of this title (relating to Definitions).

(g) **Separation of transmission and distribution utility metering system service activities.**

(1) **Metering services before the introduction of customer choice.**

(A) Affected utilities shall continue to provide metering services pursuant to commission rules and regulations provided that affected utilities do not engage in the provision of competitive energy services as defined by §25.341(6) of this title (relating to Definitions) and prescribed by §25.343 of this title (relating to Competitive Energy Services).

(B) Affected utilities may continue to use metering equipment installed, operated, and maintained by the affected utility prior to the effective date of this section, but may not use the information gained from its provision of the meter or metering services as defined in §25.341 (6)(G) of this title (relating to Definitions).

(C) When requested by the end-use customer, an affected utility shall charge the end-use customer the incremental cost for the replacement of an end-use customer's meter with an advanced meter owned, operated, and maintained by the affected utility.

(2) **Metering services on and after the introduction of customer choice until metering services become competitive.** On the introduction of customer choice in a service area, metering services as described by §25.341(27) of this title for the area shall continue to be provided by the transmission and distribution utility affiliate of the electric utility that was serving the area before the introduction of customer choice provided that the affected utility does not engage in the provision of competitive energy services as defined by §25.341 (6) of this title (relating to Definitions) and prescribed by §25.343 of this title (relating to Competitive Energy Services).

(A) **Standard meter.**

(i) The standard meter shall be owned, installed, and maintained by the transmission and distribution utility except as prescribed by PURA §39.107(a) and PURA §39.107(b).

(ii) The transmission and distribution utility shall bill a retail electric provider for non-bypassable charges based upon the measurements obtained from each end-use customer's standard meter.

(iii) If the retail electric provider requests the replacement of the standard meter with an advanced meter, the transmission and distribution utility shall charge the retail electric provider the incremental cost for the replacement of the standard meter with an advanced meter owned, operated, and maintained by the transmission and distribution utility.

(iv) Without authorization from the retail electric provider, the transmission and distribution utility's use of advanced meter data shall be limited to that energy usage information necessary for the calculation of transmission and distribution charges in accordance with that end-use customer's transmission and distribution rate schedule.

(B) **Meter reading.** Nothing in this section precludes the retail electric provider from accessing the transmission and distribution utility's standard meter for the purposes of determining an end-use customer's energy usage.

(C) **End-use customer meters.** Nothing in this section precludes the end-use customer or the retail electric provider from owning, installing, and maintaining metering equipment on the customer-premise side of the standard meter.

(D) **Advanced metering services.**

(i) The transmission and distribution utility shall not provide any advanced metering equipment or service that is deemed a competitive energy service under §25.343 of this title (relating to Competitive Energy Services).

(ii) Affected utilities may continue to use metering equipment installed, operated, and maintained by the affected utility consistent with the effective date established under paragraph (1)(B) of this subsection, but may not use the information gained from its provision of the meter or metering services as defined in §25.341(6)(G) of this title (relating to Definitions).

(iii) Without authorization from the retail electric provider, the transmission and distribution utility shall not use any advanced metering data except as prescribed by subparagraph (A)(iv) of this paragraph.

(iv) The installation of advanced metering equipment on the transmission and distribution utility's standard meter must be performed by transmission and distribution utility personnel or by contractors under the supervision of the utility.

(v) For services relating to clause (iv) of this subparagraph, the transmission and distribution utility's charges to the retail electric provider for the installation and removal of any advanced metering equipment shall be reasonable and non-discriminatory and made pursuant to a commission-approved embedded cost based tariff. Unless authorized by clause (ii) of this subparagraph or by the commission, the advanced metering equipment shall not be provided by the transmission and distribution utility.

(vi) Advanced metering equipment provided to the transmission and distribution utility for installation onto the standard meter shall meet all current industry safety standards and performance codes consistent with §25.121 of this title (relating to Meter Requirements).

(vii) All advanced metering services and related costs shall be borne by the retail electric provider.

(h) **Competitive energy services.**

(1) Nothing in this section is intended to affect the provision of competitive energy services, including those which require access to the customer's meter.

(2) An affected utility shall not provide any service that is deemed a competitive energy service under §25.341(6) of this title except as provided under §25.343 (d)(1) of this title.

(i) **Electronic data interchange.**

(1) **Standards.** All transmission and distribution utilities, retail electric providers, power generation companies, power marketers, and electric utilities shall transmit data in accordance with standards and procedures adopted by the commission.

(2) **Settlement.** All transmission and distribution utilities, retail electric providers, power generation companies, power marketers, and electric utilities shall abide by the settlement procedures adopted by the commission.

(3) **Costs.** Transmission and distribution utilities shall be allowed to recover such costs as prudently incurred in abiding by this subsection, to the extent not collected elsewhere, such as through the ERCOT-ISO fee.

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 rule §§25.341 relating to Definitions, 25.342 relating to Electric Business Separation, 25.343 relating to Competitive Energy Services, 25.344 relating to Cost Separation Proceedings, 25.345 relating to Recovery of Stranded Costs Through Competitive Transition Charge (CTC), and 25.346 relating to Separation of Electric Utility Metering and Billing Service Costs and Activities are hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 19th DAY OF JANUARY 2000.

PUBLIC UTILITY COMMISSION OF TEXAS

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Chairman Pat Wood, III

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Commissioner Judy Walsh

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Commissioner Brett A. Perlman