The Public Utility Commission of Texas (commission) proposes 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. These sections will be located in new Subchapter Q of this title (relating to Unbundling and Market Power). Project Number 21083 has been assigned to this proceeding.

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, which amends several sections of the Public Utility Regulatory Act (Vernon 1999) (PURA) was passed by the 76th Texas Legislature and is effective September 1, 1999, Act of May 27, 1999, 76th Legislature, Regular Session (1999) (SB 7). 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 recovery 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 cost 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.

The commission seeks any comments on the proposed rule that interested parties believe are appropriate. Parties should organize their comments in a manner consistent with the organization of the proposed rules.

In addition, the commission requests that interested parties specifically address the following issues:

1. Does the provision in PURA §39.252 that stranded costs 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" require that the specific numeric allocators or only the methodology for the allocator be used for the purposes of allocating ECOM among customer classes?
2. Is the allocation of stranded costs to classes pursuant to PURA §39.252 meant to fix each classes share of ECOM, or is the allocation meant to be used to design a fixed competition transition charge (CTC) charge 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 charge or more rapid collection, or should those benefits be spread over the entire system?

3. 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?

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

5. 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?

6. 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?

7. 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?

8. 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?

9. 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?

10. 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?

11. 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?

12. 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 or 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?

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

When commenting on specific subsections of the proposed rule(s), parties are encouraged to describe "best practice" examples of regulatory policies, and their rationale, that have been proposed or implemented successfully in other states already undergoing electric industry restructuring, if the parties believe that Texas would benefit from application of the same policies. The commission is only interested in receiving "leading edge" examples which are specifically related and directly applicable to the Texas statute, rather than broad citations to other state restructuring efforts.

Kit Pevoto, assistant director, Office of Regulatory Affairs, has determined that for the first five-year period the sections are in effect there will be no fiscal implications for state or local government as a result of the enforcing or administering the sections.

Ms. Pevoto also has determined that for each year of the first five years the proposed sections are in effect, the public benefit anticipated as a result of enforcing these sections will be improved regulatory oversight of electric utilities and enhanced competition in the provision of energy-related services. There will be no effect on small businesses or micro-businesses as a result of enforcing these sections.

It is anticipated that there will be no economic costs incurred by persons who are required to comply with the new sections as proposed beyond those costs caused by the underlying statutes that these new sections implement. The costs caused by the underlying statute incurred are likely to vary from utility to utility, and are difficult to ascertain. The benefits accruing from implementation of the statute by these proposed sections, however, are expected to outweigh these costs.

Ms. Pevoto also has determined that for each year of the first five years the proposed sections are in effect, there should be no effect on a local economy; therefore, no local employment impact statement is required under the Administrative Procedure Act §2001.022.

The commission staff will conduct a public hearing on this rulemaking under Government Code §2001.029 at the commission's offices, located in the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78701, on Tuesday, October 19, 1999, at 9:00 a.m.

Comments on the proposed new rules (16 copies) may be submitted to the Filing Clerk, Public Utility Commission of Texas, 1701 North Congress Avenue, PO Box 13326, Austin, Texas 78711-3326, within 25 days after publication. Reply comments may be submitted within 35 days after publication. The commission invites specific comments regarding the costs associated with, and benefits that will be gained by, implementation of the proposed section. The commission will consider the costs and benefits in deciding whether to adopt the sections. All comments should refer to Project Number 21083.

These sections are proposed 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) (SB 7), §§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 service not included and performed by the transmission and distribution utility as defined by paragraph (26) of this section.

(4) **Additional billing services —** Includes any services related to PURA §39.107(e) or other retail billing system services not included in the list of transmission and distribution utility billing 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.

(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;

(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 education, including school programs and community education activities except for those commission-approved education programs specific to transmission and distribution that do not benefit the utility's affiliate(s);

(W) advertising, except for commission-approved safety advertising specific to transmission and distribution that do not benefit the utility's affiliate(s);

(X) economic development and community affairs except for commission-approved programs specific to transmission and distribution that do not benefit the utility's affiliate(s);

(Y) 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 this section; and

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

(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 render 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) **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 programs specific to transmission and distribution;

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

(G) specific commission-approved administration of market neutral programs of incentives for energy efficiency programs, and;

(H) line safety, including tree trimming.

(22) **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.

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

qualifying power region certified under PURA §39.152, but does not include a municipally owned utility or an electric cooperative.

(24) **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 by retail electric providers;

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

(H) an operating billing system, and;

(I) error investigation and resolution.

(25) **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, and any other customer services.

(26) **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, other services and competitive energy services 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.

(3) An electric utility may request protection of its alleged confidential information.

(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 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 transmission and distribution customer who purchases the discretionary service.

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

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

(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 existing transmission and distribution system service facilities; and

(II) are provided using existing personnel and facilities that are 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 the costs and revenues for each service separately;

(II) offer the service on a non-discriminatory-basis, and if 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 are not to 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).

(c) **Competitive energy service separation.** Affected utilities shall not provide competitive energy services after September 1, 2000.

(d) **Petitions to provide competitive energy services.**

(1) If a utility finds that a service which is otherwise a competitive energy service, is not available to customers in an area, the utility may petition the commission to provide that service to that area on an unbundled tariffed basis. 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 and the commission's control to correct. When a petition

under this subsection is granted, the utility shall provide the specific service pursuant to a fully embedded cost-based tariff. The costs associated with providing this service shall be tracked separately from other transmission and distribution utility costs.

(2) An affected person or the Office of Regulatory Affairs may also 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.

(e) **Filing.** Affected utilities shall file descriptions of each competitive energy service provided by the utility as part of their business separation plans filed pursuant to §25.342 of this title (relating to Electric Business Separation). The business separation plans shall include a detailed plan for completely and fully separating competitive energy services.

§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 tariffs 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, municipal franchise charges, 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 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 UCOS-RFP approved by the commission.

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

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

(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 school funding loss mechanism to allow school districts to recover property tax revenues lost due to electric utility restructuring. 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.

(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 eight 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 billing services;

(G) transmission and distribution utility customer service; and

(H) competitive energy service.

(3) **Method of cost separation.** Costs shall be assigned to the eight functions using the following three-tier process. No common costs will be assigned to regulated functions by default. If the utility cannot meet its burden of proof, the costs in question will 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 allocator based on the directly assigned costs. The utility must justify the allocation of common costs to regulated functions, and must present evidence to support any such allocation.

(C) If adequately documented costs remain for which no direct assignment or account-specific allocation is possible, the appropriate functionalization factor prescribed in the UCOS-RFP may be used. These functionalization factors should only be used as a last resort. If a utility deems an allocator other than the allocator prescribed in these instructions to be necessary, the utility shall provide a detailed justification for the chosen allocator.

(h) **Jurisdiction and Texas retail class allocation.** Allocation of 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 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 eight categories shall be allocated among existing rate classes. Consolidation of classes shall be done only during 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 company (as a wires company) system peak. Non-ERCOT utilities shall allocate transmission revenue requirement based on either 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 last cost of service study unless approved otherwise 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 approved 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 approved 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.

(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 by the electric utilities under this section will provide additional details concerning the electric utility costs that may be included in the ERCOT annual transmission costs.

(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 the purposes of determination of 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 may 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 and PURA §39.201, relating to Cost of Service Tariffs and Charges, 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 who 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;

(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.

(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 stranded costs from the wholesale customers, retail customers shall not be adversely affected by this decision.

(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. An electric utility may protect its alleged confidential information.

(g) **Recovery of stranded costs through securitization.** An electric utility, which 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 which 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 which 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 UCOS-RFP approved by the commission.

(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 relevant class characteristics as of May 1, 1999, adjusted for normal weather conditions.

(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**. A retail customer 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 it receives 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.

(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.

(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 may 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, Standby and Maintenance. 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).

(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(24) of this title (relating to Definitions).

(2) Charges for transmission and distribution 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(24) 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) All additional billing services 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 competitive energy services function, as defined in §25.344(g)(2)(H) 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 described in §25.341(26) of this title.

(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.

(B) 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 provided by the customer's 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(26) 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.

(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) 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 provided by the transmission and distribution utility.

(iii) 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.

(iv) Nothing in this section shall preclude the continued use of meters in service at the effective date of this section.

(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 reading the end-use customer's meter in addition to the transmission and distribution utility.

(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) All advanced metering services and related costs shall be borne by the retail electric provider.

(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)(iii) of this paragraph.

(iv) Any installation of metering equipment on the transmission and distribution utility's meter or on the transmission and distribution utility's side of the meter must be performed by transmission and distribution personnel or by contractors working for the transmission and distribution utility and under its supervision.

(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.

(vi) Any metering equipment shall meet all current industry safety standards and performance codes consistent with §25.121 of this title (relating to Meter Requirements).

(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.

(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.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's authority to adopt.

ISSUED IN AUSTIN, TEXAS ON THE 30th DAY OF AUGUST 1999 BY THE PUBLIC UTILITY COMMISSION OF TEXAS
RHONDA G. DEMPSEY