The Public Utility Commission of Texas (commission) adopts amendments to §25.192 relating to Transmission Service Pricing, and §25.236 relating to Recovery of Fuel Costs, with changes to the proposed text as published in the July 30, 1999 *Texas Register* (24 TexReg 5826). The amendments are necessary to permit the independent system operator (ISO) for the Electric Reliability Council of Texas (ERCOT) to begin funding the additional functions that will be required to implement competition in the retail sale of electricity. These amendments are adopted under Project Number 21066.

Senate Bill 7 (SB 7) was enacted by the 76th Legislature, Regular Session (1999) to introduce competition in the retail sale of electricity in Texas, beginning in 2002. The bill requires the establishment of an independent organization to carry out certain functions that are essential to the operation of a competitive retail electric market. The ERCOT ISO will have significantly greater responsibilities and workload as the independent organization for ERCOT than it has today. It has begun planning for its additional manpower and other resource needs, so that the additional personnel and systems are in place and operational by the summer of 2001 for the pilot project in retail competition that is required by SB 7. The amendment to §25.192 will require utilities to make payments to the ISO, providing it current funding to assume its additional responsibilities without undue financial burden. The amendment to §25.236 will permit utilities to recover from their customers as fuel costs the new fees they pay the ISO.

A public hearing on the amendments was held at the commission offices on September 2, 1999 at 9:00 a.m. Representatives from TXU Electric, Reliant Energy, Texas Industrial Energy Consumers, and Consumers Union attended the hearing and provided comments. To the extent that these comments differ from the written statements they submitted, such comments are summarized below.

The commission received written comments on the proposed amendments from Central Power & Light Company and West Texas Utilities Company (CSW Companies), the Office of Public Counsel (Public Counsel), Texas-New Mexico Power Company (TNMP), the City Public Service Board of the City of San Antonio (San Antonio), TXU Electric, Reliant Energy, and Texas Industrial Energy Consumers (TIEC).

None of the parties that commented on the amendments opposed the adoption of the amendment to §25.192, which would impose an ISO fee on wholesale power transactions that are scheduled using planned transmission service. The CSW Companies and TNMP supported the concept of adequate funding for the ISO. Several parties proposed modifications or clarifications of this section. The utilities that filed comments also supported the amendment to §25.236, which permits the recovery of the ISO fees from retail customers through the fuel expenses. Several other parties opposed this amendment, arguing that the commission should not permit utilities to recover the new ISO fee through fuel charges. TIEC and the Public Counsel also argued that the cost allocation that would result from the inclusion of the ISO fee in fuel charges would be inappropriate. The commission concludes that additional funding of the ERCOT ISO to permit it to prepare for retail competition will facilitate the achievement of an important public policy, the timely introduction of effective retail competition, and that assuring utilities' recovery of the new fees they pay the ISO also supports this policy. The commission is adopting the rule without substantive changes to the proposal that was published in the *Texas Register* but is adopting clarifications of the proposed rules, as suggested by some of the parties.

San Antonio argued that the proposed funding mechanism is not competitively neutral. The amended Public Utility Regulatory Act (PURA), in §39.151(e), authorizes the commission to prescribe a fee to recover the costs of an independent organization, but it requires that the fee be reasonable and competitively neutral. San Antonio argued that under the fee in the proposed amended §25.192, the majority of the independent organization's start up costs will be paid by existing load-serving entities, and that new market entrants will be able to avoid payment of the bulk of the initial costs of the ISO. San Antonio proposed that (1) the funding mechanism in the proposed rule should be in effect until January 1, 2002; and (2) upon the implementation of full retail competition in ERCOT, the ISO funding rate for those load-serving entities that contributed to increased ISO funding prior to 2002 should be set at a level lower than the rate for new companies entering the marketplace, until the new entrants have paid fees equal to the amount contributed by the pre-2002 entities. As San Antonio recognizes, there is a fairness issue in requiring funding today, when the new competitive companies are not operating in Texas to any significant degree. This would be a particularly significant problem if the current retailers of electricity were not permitted to pass the ISO fees on to their customers. The proposed amendment of §25.236, however, will permit regulated utilities to recover these costs from their customers, and unregulated municipal utilities and cooperatives have the right to recover these costs from their retail customers, without any action by the commission. In short, the retailers of electricity will be able to pass these costs on to their customers in the period before retail competition begins, so there should be little or no competitive impact from permitting the ISO to impose these fees. The more important issue will be how to recover the ISO's costs after competition begins. The solution proposed by San Antonio raises more difficult competitive issues than it resolves, because it would have two competitors in the same market paying a different level of fees. There are legitimate issues about how the ERCOT ISO should recover its costs, but the commission does not intend that the mechanism being adopted in this rule be permanent. As is discussed below, subsequent proceedings will afford the commission a better opportunity to resolve these issues in the context of a broader public discussion of the organization and funding of the ERCOT ISO.

The CSW Companies, TXU Electric, and TNMP urged the commission to clarify that the ISO fee applies to annual, monthly, weekly, and daily planned service. These parties suggested modifications to §25.192(a) and (f) to make this point clear. The commission is adopting modifications to the rule to make this point clear. TXU Electric also suggested that the third sentence of §25.192(a) be amended to reflect the current practice of assessing loss compensation charges for transmission customers that take weekly and daily transmission service. The commission is adopting a clarification on this point.

TNMP recommended that the commission adopt the postage-stamp transmission pricing required by SB 7 and that the commission establish a procedure for the review of the budget of the ISO. It also recommended that the costs of the ERCOT administrative office not be recovered through the fee established in §25.192. The proposal relating to postage-stamp pricing is beyond the scope of the proposed rule, and it would be unfair to adopt this change in this proceeding without more specific notice of the commission's intention to do so. With regard to budget review, the current §25.192(f) requires commission approval prior to a change in the ISO fee. In addition, the ERCOT ISO is expected to make a filing in October to request certification as the independent organization for ERCOT under PURA §39.151. That filing should cover the organization and funding of the ISO, and the commission's review of that filing or the adoption of rules to implement PURA §39.151 is a more appropriate mechanism to address the issues raised by TNMP. These issues should be discussed within ERCOT before it makes the October filing, affording interested persons an opportunity for a fuller airing of the issue and possibly a consensual resolution. Accordingly, the commission is not adopting TNMP's suggestions in this rulemaking proceeding.

A number of parties argued that the funding mechanism in the proposed rule should be limited to the period before the introduction of retail competition. Public Counsel, for example, argued that both the level of required funding and the volume of transactions are likely to change once the infrastructure for the retail market is in place and competition begins. The commission agrees with these comments. In the preamble to the proposed rule, the commission noted that the purpose of the rule was to "to permit the ISO to begin funding the additional functions that will be required to implement competition in the retail sale of electricity." The level of funding certainly will change over time, and the funding mechanism that is appropriate for a competitive market is likely to be different than the mechanism that is being adopted for the transition period. The commission is not revising the text of the rule on this point, but it is committed to a resolution of this issue for the period when competition begins that includes a fuller discussion of the costs involved and how they will be recovered in a competitive market.

The Public Counsel, Consumers Union, and TIEC challenged the commission's proposal to permit utilities to recover fees paid to the ISO through fuel charges. Consumers Union noted that the amended PURA includes a freeze on the base rates of investor-owned utilities and argued that the fuel charges, which are not subject to the freeze, should not be used to increase rates for customers. Public Counsel noted that §39.004(d) permits utilities to adjust their wholesale transmission rates during the rate freeze or report transmission costs in excess of transmission revenues as expenses for the annual reports required in §39.052. Public Counsel argued that the amended law contemplates that transmission expenses be included in the annual report, not included in fuel expenses. TIEC argued that in other areas utility costs are going down, so that permitting the recovery of this new expense may lead to over-recoveries of base rates by utilities. In response, Reliant Energy argued that including the ISO charges in fuel costs does not imply that rates will change. It simply means that the charges will be recorded as fuel expenses that will be subject to a future reconciliation of fuel revenues and expenses. Reliant Energy also argued that ISO fees for unplanned transmission service are treated as fuel expenses under the current §25.236, and that the same treatment is appropriate for ISO fees for planned service. Reliant Energy also challenged TIEC's assertion that utility costs are going down.

The commission agrees with the position of Reliant Energy concerning the effect of the rate freeze in SB 7. The freeze does not preclude the commission from treating the ISO fees as fuel expenses. Under the current §25.236, some transmission-related costs are included in eligible fuel expenses and some are excluded. The commission recently amended §25.236 and clarified the treatment of transmission-related costs. One of its conclusions was to not include payments of transmission facilities charges to other utilities as fuel expenses. It reached its conclusion on this issue based on policy considerations, primarily that it would not be appropriate for large increases in transmission costs to be passed through to customers by means of the utilities' fuel charges, when the ERCOT utilities had had an opportunity to file rate cases to reflect the increases in transmission costs in their rates. The magnitude of the ISO fees that will be paid under this rule is smaller than the transmission-cost increases at issue in the prior amendment of §25.236, and base rates are now frozen, in accordance with the recent amendments to PURA. Nevertheless, the costs at issue here are important to meeting the new statutory requirement to introduce retail competition in January 2002. TIEC made the point in its comments that the commission should not implement a retail pass-through of the costs unless there are important policy reasons for doing so. The commission agrees with this position but concludes that funding the ISO is sufficiently important that investor-owned utilities should be permitted to pass the costs through to their retail customers. The competitive issue raised by San Antonio also supports this outcome. If investor-owned utilities are not able to pass these costs through to their retail customers, they may be at a competitive disadvantage with respect to new market entrants, who will not bear this cost during the 2000-2001 period, and municipal utilities and cooperatives, who do not need commission approval to recover these costs from their customers.

Public Counsel and TIEC also argued that the inclusion of ISO fees in fuel expenses is inappropriate on cost-allocation grounds. TIEC argued that the costs should not be allocated among customers based on energy consumption. It argued that the costs are demand-related and should be recovered through a mechanism that will permit them to be allocated to customers on the basis of demand for energy. In response, Reliant and TXU Electric argued that it is appropriate to include the costs in fuel. TXU Electric argued that the commission precedent on fuel expenses provides sufficient latitude to include these costs in fuel expenses. Reliant argued that for administrative efficiency and to permit future review of the expenses, the commission should include the costs in fuel expenses. The commission notes that including the costs in fuel expenses is administratively efficient. It will give utilities assurance of recovery of the amounts paid to the ISO, while preserving them for future review in a fuel reconciliation proceeding. If they were treated as base-rate expenses, they would have to be recorded as an expense on a current basis. At the same time, the expense caps in PURA §39.258 might not permit a utility to include the costs in its annual report of revenues and expenses. As is noted above, the commission concludes that the payment of these fees to the ISO to permit it to prepare for retail competition is an important public policy, and that assurance of recovery of the costs by utilities supports this policy. In addition, it is not clear that the costs at issue should be allocated on the basis of demand, as TIEC asserted. Transmission facilities have historically been allocated on the basis of demand, but where the fee is assessed to the utility on an energy basis, it is appropriate for the utility to recover it on that same basis.

TXU Electric argued that the commission should clarify the amendment to §25.236, adding a phrase that would state that the ISO fees are presumed to be reasonable. The commission concludes that this addition is not necessary. It is difficult to see how expenses paid by a utility to the ISO pursuant to a commission rule could be challenged in a fuel reconciliation proceeding.

All comments, including any not specifically summarized in this document, were fully considered by the commission.

These amendments are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated, as amended by Senate Bill 7, Act of May 27, 1999, 76th Legislature, Regular Session, chapter 405, 1999 Texas Session Law Service 2543 (Vernon) (PURA), §14.002 which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; PURA §31.001, which declares that the public interest requires that rules, policies and principles be formulated and applied to protect the public interest in a more competitive marketplace; §35.004, which requires utilities to provide comparable wholesale transmission service, directs the commission to ensure that utilities provide non-discriminatory transmission service, and requires the commission to adopt reasonable rates for transmission service; §35.005, which permits the commission to require an electric utility to provide wholesale transmission service, determine whether the terms and conditions of such service are reasonable, and require the construction or enlargement of a transmission facility; §35.006, which directs the commission to adopt rules relating to wholesale transmission service; and §39.151, which requires that an independent organization be established in each power region and authorizes the commission to adopt a reasonable and competitively-neutral fee to cover the costs of an independent organization.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 31.001, 35.004, 35.005, 35.006, and 39.151.

Subchapter I. Transmission and Distribution.
Division 1. Open-access Comparable Transmission Service for Electric Utilities in the Electric Reliability Council of Texas.

§25.192. Transmission Service Rates.

(a) **Charges for transmission service.** Transmission service customers shall incur facilities charges, loss compensation charges, and an independent system operator (ISO) fee for all planned transmission service. Transmission service customers shall incur loss compensation charges and an ISO fee for unplanned transmission service. The facilities charge for annual and monthly planned transmission service shall consist of an access fee and an impact fee. Facilities charges shall be determined in transmission ratemaking proceedings conducted periodically, at such intervals as the commission determines are appropriate.

(1) The costs included in the access fee will be seven-tenths of the annual cost of transmission service for each transmission service provider in the Electric Reliability Council of Texas (ERCOT). A transmission service customer taking planned transmission service will pay a share of these costs, based on its share of the total load in ERCOT.

(A) For each transmission service provider, an access rate will be calculated by dividing seven-tenths of the transmission service provider's annual transmission cost of service by the total ERCOT load, as calculated in accordance with this section.

(B) Each transmission service customer taking annual planned transmission service will pay an access charge to transmission service providers, calculated by multiplying the applicable access rate by the transmission service customer's peak load, as calculated in accordance with this section.

(2) The costs included in the impact fee will be three-tenths of each transmission service provider's annual cost of transmission service. A transmission service customer taking planned transmission service will pay an impact fee to the transmission service providers, based on the impact of transmitting its resources to its loads, calculated using the vector-absolute megawatt-mile method for assessing impacts.

(A) For each transmission service provider, a megawatt-mile rate will be calculated by dividing three-tenths of the transmission service provider's annual transmission costs, as determined in accordance with this section, by the sum of the megawatt-mile impacts of all planned resources on the transmission service provider's system, using the impacts calculated in accordance with §25.194 of this title (relating to Determining Peak Loads and Megawatt-Mile Impacts).

(B) Each transmission service customer taking annual planned transmission service will pay an impact charge to transmission service providers, calculated by multiplying the applicable rate by the impact of the transmission service customer's planned resources on the transmission service provider's system, as calculated in accordance with §25.194 of this title.

(3) In adopting facilities charges under this section, the commission shall apply a transition mechanism in 1999 to reduce the impact of the changes in the level of transmission charges under this section on an electric utility or its customers. In applying this transition mechanism, the commission shall calculate the "unadjusted rate impact" for each electric utility, which shall be the difference between the facilities charge and the transmission revenues an electric utility would receive under this section, both calculated at the time transmission rates were first determined under the commission's open-access transmission rules, and without regard to any adjustment under this paragraph. An adjustment shall be made to the 1999 facilities charge equal to 70% of the difference between the 1997 facilities charge incurred by an electric utility and its annual transmission cost of service for calendar year 1997.

(4) The commission may adjust the facilities charges under this section to account for any transmission revenues that an electric utility receives under an existing transmission contract.

(5) The facilities charge for the short-term planned service described in §25.198 of this title (relating to Initiating Transmission Service) will be based on a prorated portion of seven-tenths of the annual cost of transmission service for each transmission service provider and will be charged on the basis of the megawatts of transmission service that are reserved. A transmission service customer will be obligated to pay all transmission service providers for this service upon making a

request, whether the customer uses the service or not. Transmission service providers shall file tariffs for this service for commission approval.

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

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

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

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

(C) the portion of the direct-current (DC) interconnections with the Southwest Power Pool that are owned by a transmission service provider in ERCOT; and

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

(2) In determining the annual transmission cost of service under this subsection, the following expenses shall not be included:

(A) expenses of an electric utility that are otherwise included in its annual transmission cost for service under any existing transmission contract (including the value of goods and services exchanged for transmission service);

(B) transmission expenses paid to another electric utility in accordance with this section; and

(C) expenses for transmission service outside of ERCOT.

(3) For municipal utilities, river authorities, and electric cooperatives, the commission may permit the use of reasonable alternative methods of determining the annual cost of transmission service, including the cash flow method, consistent with the rate actions of the rate-setting authority for a municipal utility, and an alternative method for determining the utility's return, as permitted in paragraph (4) of this subsection.

(4) For municipal utilities, river authorities, and electric cooperatives, the return may be determined based on the electric utility's actual debt service and a reasonable

coverage ratio. In determining a reasonable coverage ratio, the commission will consider the coverage ratios required in the electric utility's bond indentures or ordinances and the most recent rate action of the rate-setting authority for the electric utility.

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

(c) **Billing units.** As used in this section, a transmission service customer's system demand is the average of the demand of the transmission service customer's retail and wholesale customers for hours that are coincident with the most recent ERCOT system coincident peak demand. In determining a transmission service customer's demand and ERCOT system coincident peak demand, the actual demand on electric utility systems shall be considered, and the ERCOT system coincident peak demand shall be an average of the highest aggregate demand in each of the months of June, July, August, and September of the relevant period. Actual electric utility demand shall be calculated based on the electric utility's net hourly generation, plus wholesale purchases, minus wholesale sales.

(1) The megawatt-mile impact of transmitting resources to load shall be calculated using the loads and resources at the ERCOT peak and shall be calculated by the independent system operator or calculated under its supervision. Megawatt-mile impacts shall be calculated in the manner prescribed in §25.194 of this title.

(2) Peak demand and megawatt-mile impact may be adjusted for known and measurable changes to wholesale customer loads and resources, when such changes can be identified and quantified with reasonable certainty.

(d) **Transmission revenue.** The facilities charges prescribed in subsection (a) of this section are intended to provide each transmission service provider an opportunity to recover its transmission cost of service. Revenue from the transmission of electric energy out of ERCOT over the DC ties that is not recovered through rates for annual planned transmission service and revenue from monthly, weekly, and daily planned transmission service shall be credited to all transmission service customers as a reduction in the transmission cost of service for transmission service providers that receive the revenue.

(e) **Compensation for losses.** A transmission service customer that uses transmission service to transmit power to its loads shall compensate affected control-area utilities for energy losses resulting from such transmission service. Losses shall be calculated by the independent system operator under a method approved by the commission. The method of compensation for losses shall provide reasonably accurate compensation for the cost of supplying losses incurred under different system conditions.

(f) **Independent system operator charges.** Transmission service customers shall incur an ISO fee for planned transmission service and unplanned transmission service, payable to the independent system operator. Changes in the fee are subject to approval by the commission.

(g) **Inadvertent energy.** Control-area utilities shall compensate each other for inadvertent energy flows under a tariff requiring monetary payments. The independent system operator shall develop any necessary procedures to implement this subsection.

(h) **Transmission rates for exports from ERCOT.** Facilities charges, ISO charges, and loss compensation for exports of power from ERCOT will be assessed to transmission service customers for that portion of transmission that is within the boundaries of ERCOT, in accordance with this section.

(1) For the purposes of facilitating these transactions, the annual facilities charge shall be prorated on a monthly, weekly, daily and hourly basis.

(2) Transmission service customers exporting power from ERCOT on an unplanned basis will be assessed an access charge based on the duration of the transaction, and will be charged only for the transmission service actually used. Transmission service customers exporting power from ERCOT on a planned basis will be assessed an access charge based on duration of the service requested.

(3) The monthly on-peak access fee will be one-fourth the annual rate, and the monthly off-peak access fee will be one-twelfth the annual rate. The peak period used to determine the applicable transmission rate for such transactions shall be

the months of June, July, August, and September. The impact charge will be calculated in accordance with this section.

Subchapter J. Costs, Rates and Tariffs.

§25.236. Recovery of Fuel Costs.

(a) **Eligible fuel expenses.** Eligible fuel expenses include expenses properly recorded in the Federal Energy Regulatory Commission Uniform System of Accounts, numbers 501, 503, 518, 536, 547, 555, and 565, as modified in this subsection, as of April 1, 1997, and the items specified in paragraph (7) of this subsection. Any later amendments to the System of Accounts are not incorporated into this subsection. Subject to the commission finding special circumstances under paragraph (6) of this subsection, eligible fuel expenses are limited to:

(1) For any account, the electric utility may not recover, as part of eligible fuel expense, costs incurred after fuel is delivered to the generating plant site, for example, but not limited to, operation and maintenance expenses at generating plants, costs of maintaining and storing inventories of fuel at the generating plant site, unloading and fuel handling costs at the generating plant, and expenses associated with the disposal of fuel combustion residuals. Further, the electric utility may not recover maintenance expenses and taxes on rail cars owned or leased by the electric utility, regardless of whether the expenses and taxes are incurred or charged before or after the fuel is delivered to the generating plant site.

The electric utility may not recover an equity return or profit for an affiliate of the electric utility, regardless of whether the affiliate incurs or charges the equity return or profit before or after the fuel is delivered to the generating plant site. In addition, all affiliate payments must satisfy the Public Utility Regulatory Act (PURA) §36.058.

(2) For Accounts 501 and 547, the only eligible fuel expenses are the delivered cost of fuel to the generating plant site excluding fuel brokerage fees. For Account 501, revenues associated with the disposal of fuel combustion residuals will also be excluded.

(3) For Accounts 518 and 536, the only eligible fuel expenses are the expenses properly recorded in the Account excluding brokerage fees. For Account 503, the only eligible fuel expenses are the expenses properly recorded in the Account, excluding brokerage fees, return, non-fuel operation and maintenance expenses, depreciation costs and taxes.

(4) For Account 555, the electric utility may not recover demand or capacity costs.

(5) For Account 565, an electric utility may not recover transmission expenses paid to affiliated companies for the purpose of equalizing or balancing the financial responsibility of differing levels of investment and operating costs associated with transmission assets. A non-ERCOT electric utility may not recover expenses for wheeling transactions. An ERCOT electric utility may recover only the expenses properly recorded in Account 565 for ISO fees related to planned and unplanned

transmission service and for payments to parties related to unplanned transmission service, such as losses and re-dispatch fees.

(6) Upon demonstration that such treatment is justified by special circumstances, an electric utility may recover as eligible fuel expenses fuel or fuel related expenses otherwise excluded in paragraphs (1) - (5) of this subsection. In determining whether special circumstances exist, the commission shall consider, in addition to other factors developed in the record of the reconciliation proceeding, whether the fuel expense or transaction giving rise to the ineligible fuel expense resulted in, or is reasonably expected to result in, increased reliability of supply or lower fuel expenses than would otherwise be the case, and that such benefits received or expected to be received by ratepayers exceed the costs that ratepayers otherwise would have paid or otherwise would reasonably expect to pay.

(7) Eligible fuel expenses shall not be offset by revenues by affiliated companies for the purpose of equalizing or balancing the financial responsibility of differing levels of investment and operation costs associated with transmission assets. In addition to the expenses designated in paragraphs (1) - (6) of this subsection, unless otherwise specified by the commission, eligible fuel expenses shall be offset by:

(A) revenues from steam sales included in Accounts 504 and 456 to the extent expenses incurred to produce that steam are included in Account 503; and

(B) revenues from wheeling transactions except for non-ERCOT electric utilities; and

(C) revenues from off-system sales in their entirety, except as permitted in paragraph (8) of this subsection.

(D) For electric utilities in ERCOT, revenues from third parties for unplanned transmission service, such as ISO fees, losses, and re-dispatch fees.

(8) **Shared margins from off-system sales.** An electric utility may retain 10% of the margins from an off-system energy sales transaction if the following criteria are met:

(A) the electric utility participates in a transmission region governed by an independent system operator or a functionally equivalent independent organization;

(B) a generally-applicable tariff for firm and non-firm transmission service is offered in the transmission region in which the electric utility operates; and

(C) the transaction is not found to be to the detriment of its retail customers.

(b) **Reconciliation of fuel expenses.** Electric utilities shall file petitions for reconciliation on a periodic basis so that any petition for reconciliation shall contain a maximum of three years and a minimum of one year of reconcilable data and will be filed no later than six months after the end of the period to be reconciled. However, notwithstanding the previous sentence, a reconciliation shall be requested in any general rate proceeding under the PURA, Chapter 36, Subchapters C and E and may be performed in any general rate proceeding under the PURA, Chapter 36, Subchapter D. Upon motion and showing of good cause, a fuel reconciliation proceeding may be severed from or consolidated with other proceedings.

(c) **Petitions to reconcile fuel expenses.** In addition to the commission prescribed reconciliation application, a fuel reconciliation petition filed by an electric utility must be accompanied by a summary and supporting testimony that includes the following information:

(1) a summary of significant, atypical events that occurred during the reconciliation period that affected the economic dispatch of the electric utility's generating units, including but not limited to transmission line constraints, fuel use or deliverability constraints, unit operational constraints, and system reliability constraints;

(2) a general description of typical constraints that limit the economic dispatch of the electric utility's generating units, including but not limited to transmission line constraints, fuel use or deliverability constraints, unit operational constraints, and system reliability constraints;

(3) the reasonableness and necessity of the electric utility's eligible fuel expenses and its mix of fuel used during the reconciliation period;

(4) a summary table that lists all the fuel cost elements which are covered in the electric utility's fuel cost recovery request, the dollars associated with each item, and where to find the item in the prefiled testimony;

(5) tables and graphs which show generation (MWh), capacity factor, fuel cost (cents per kWh and cents per MMBtu), variable cost and heat rate by plant and fuel type, on a monthly basis; and

(6) a summary and narrative of the next-day and intra-day surveys of the electricity markets and a comparison of those surveys to the electric utility's marginal generating costs.

(d) **Fuel reconciliation proceedings.** Burden of proof and scope of proceeding are as follows:

(1) In a proceeding to reconcile fuel factor revenues and expenses, an electric utility has the burden of showing that:

(A) its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers;

(B) if its eligible fuel expenses for the reconciliation period included an item or class of items supplied by an affiliate of the electric utility, the prices charged by the supplying affiliate to the electric utility were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items; and

(C) it has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period.

(2) The scope of a fuel reconciliation proceeding includes any issue related to determining the reasonableness of the electric utility's fuel expenses during the reconciliation period and whether the electric utility has over- or under-recovered its reasonable fuel expenses.

(e) **Refunds.** All fuel refunds and surcharges shall be made using the following methods.

(1) Interest shall be calculated on the cumulative monthly ending under- or over-recovery balance at the rate established annually by the commission for overbilling and underbilling in §25.28 (c) and (d) of this title (relating to Bill Payment and Adjustments). Interest shall be calculated based on principles set out in subparagraphs (A) - (E) of this paragraph.

(A) Interest shall be compounded annually by using an effective monthly interest factor.

(B) The effective monthly interest factor shall be determined by using the algebraic calculation $x = (1 + i)^{(1/12)} - 1$; where i = commission-approved annual interest rate, and x = effective monthly interest factor.

(C) Interest shall accrue monthly. The monthly interest amount shall be calculated by applying the effective monthly interest factor to the previous month's ending cumulative under/over recovery fuel and interest balance.

(D) The monthly interest amount shall be added to the cumulative principal and interest under/over recovery balance.

(E) Interest shall be calculated through the end of the month of the refund or surcharge.

(2) Rate class as used in this subparagraph shall mean all customers taking service under the same tariffed rate schedule, or a group of seasonal agricultural customers as identified by the electric utility.

(3) Interclass allocations of refunds and surcharges, including associated interest, shall be developed on a month-by-month basis and shall be based on the historical kilowatt-hour usage of each rate class for each month during the period in which the cumulative under- or over-recovery occurred, adjusted for line losses using the same commission-approved loss factors that were used in the electric utility's applicable fixed or interim fuel factor.

(4) Intraclass allocations of refunds and surcharges shall depend on the voltage level at which the customer receives service from the electric utility. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the electric utility shall be given refunds or assessed surcharges based on their individual actual historical usage recorded during each month of the period in which the cumulative under- or over-recovery occurred, adjusted for line losses if necessary. All other customers shall be given refunds or assessed surcharges based on the historical kilowatt-hour usage of their rate class.

(5) Unless otherwise ordered by the commission, all refunds shall be made through a one-time bill credit and all surcharges shall be made on a monthly basis over a

period not to exceed 12 months through a bill charge. However, refunds may be made by check to municipally-owned electric utility systems if so requested. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the electric utility shall be given a one-time credit or assessed a surcharge made on a monthly basis over a period not to exceed 12 months through a bill charge. All other customers shall be given a credit or assessed a surcharge based on a factor which will be applied to their kilowatt-hour usage over the refund or surcharge period. This factor will be determined by dividing the amount of refund or surcharge allocated to each rate class by forecasted kilowatt-hour usage for the class during the period in which the refund or surcharge will be made.

(6) A petition to surcharge or refund a fuel under- or over-recovery balance not associated with a proceeding under subsection (d) of this section shall be processed in accordance with the filing schedules in §25.237(d) of this title (relating to Fuel factors) and the deadlines in §25.237(e) of this title.

(f) **Procedural schedule.** Upon the filing of a petition to reconcile fuel expenses in a separate proceeding, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within one year after a materially complete petition was filed. However, if the deadlines result in a number of electric utilities filing cases within 45 days of each other, the presiding officers shall schedule the cases in a manner to allow the commission to accommodate the workload of the cases irrespective of whether such procedural schedule enables the commission to issue a final order in each of the cases within one year after a materially complete petition is filed.

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 §25.192 and §25.236 are hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 10th DAY OF SEPTEMBER 1999.

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