PROJECT NO. 54844

MINOR AND CONFORMING RULE UPDATES 2023	**§**	**PUBLIC UTILITY COMMISSION**
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	§	**OF TEXAS**

CHAPTER 25

ORDER ADOPTING AMENDMENTS TO §§25.31, 25.231 25.238 25.240, 25.271, 25.301, 25.483, AND 25.486 AS APPROVED AT THE JUNE 29, 2023 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to §25.31 relating to Information to Applicants and Customers, §25.238, relating to Purchased Power Capacity Cost Recovery Factor (PCRF); §25.240, relating to Contribution Disclosure Statements in Appeals of Municipal Utility Rates, §25.271, relating to Foreign Utility Company Ownership by Exempt Holding Companies, §25.301, relating to Nuclear Decommissioning Trusts; §25.483, relating to Disconnection of Service, and §25.486, relating to Customer Protections for Brokerage Services with no changes to the proposed text as published in the May 12, 2023, issue of the *Texas Register* (48 TexReg 2453). The amended rules with no change will not republished. The commission adopts amendments to §25.231, relating to Cost of Service with changes to the proposed text as published in the May 12, 2023 issue of the Texas Register (48 TexReg 2453). The amended rule with change will be republished.

The adopted amendments are administrative in nature to update contact resources used by individuals with hearing or speech difficulties and also to make other minor and conforming amendments. These amendments are adopted under Project Number 54844.

The commission received comments on the proposed rule from Alliance for Retail Markets' (ARM) and Texas Electric Cooperatives, Inc (TEC).

§25.231(c)(1)(B)

Existing §25.231(c)(1)(B) requires the commission to consider specific factors along with other applicable conditions and practices when fixing the rate of return for a utility's invested capital.

TEC commented that proposed §25.231(c)(1)(B) as replaces an obligatory *shall* with a permissive *may*, allowing the commission to elect whether to consider the specific considerations when setting a rate of return. TEC requested that the language remain obligatory to remain consistent with statutory language. TEC also argues that the proposed language is too significant to be styled as a minor or conforming change and should be considered in a longer rulemaking process.

Commission Response

The commission agrees with TEC that the change in language from shall to may is inconsistent with the statutory language and modifies the requirement to remain obligatory.

§25.483(g)(4)

Section 25.483(g)(4) requires a transmission and distribution utility (TDU) to cease charging a retail electric provider (REP) most transmission and distribution charges for the premises of a critical care residential customer that the TDU refuses to disconnect.

ARM requested that the process for a TDU to cease transmission and distribution charges in this context be streamlined.

Commission Response

ARM's request for a streamlined §25.483(g)(4) is outside of the scope of what was noticed in this project. The requested modifications may be considered in a future rulemaking project.

§25.483(j)

Section 25.483(j) prohibits REPs from authorizing the disconnection of a customer for non-payment during an extreme weather emergency.

ARM requested that §25.483(j) be modified to clarify the process for extreme weather moratoriums on disconnection for non-payment and provided language consistent with its proposed change.

ARM further requested the addition of a new paragraph to standardize the timelines for a REP to cease requesting disconnections for non-payment when a TDU makes that determination and sends notice to the commission and REPs. ARM provided the following language:

> **§25.483(j)(3)** A REP must discontinue authorizations of disconnections for non-payment within two hours of receiving notice that a TDU has determined that an extreme weather emergency has been issued for a county in its service area.

Commission Response

ARM's requested changes are outside of the scope of what was noticed in this rulemaking project. The requested modifications may be considered in a future rulemaking project.

The rules are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 and §14.052, which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction, including rules of practice and procedure.

Cross Reference to Statutes: Public Utility Regulatory Act §14.002 and §14.052.

§25.31. Information to Applicants and Customers.

(a) **Information to applicants.** Each electric utility must provide this information to applicants when they request new service or transfer existing service to a new location:

(1) the electric utility's lowest-priced alternatives available at the applicant's location. The information must begin with the lowest-priced alternative and give full consideration to applicable equipment options and installation charges;

(2) the electric utility's alternate rate schedules and options, including time of use rates and renewable energy tariffs if available; and

(3) the customer information packet described in subsection (c) of this section. This is not required for the transfer of existing service.

(b) **Information regarding rate schedules and classifications and electric utility facilities.**

(1) Each utility must notify customers affected by a change in rates or schedule of classifications.

(2) Each electric utility must maintain copies of its rate schedules and rules in each office where applications are received.

(3) Each electric utility must post a notice in a conspicuous place in each office where applications are received, informing the public that copies of the rate schedules and rules relating to the service of the electric utility, as filed with the commission, are available for inspection.

(4) Each electric utility must maintain a current set of maps showing the physical locations of its facilities that includes an accurate description of all facilities (substations, transmission lines, etc.). These maps must be kept by the electric utility in a central

location and will be available for commission inspection during normal working hours. Each business office or service center must have available up-to-date maps, plans, or records of its immediate service area, with other information as may be necessary to enable the electric utility to advise applicants, and others entitled to the information, about the facilities serving that locality.

(c) **Customer information packets**.

(1) The information packet must be entitled "Your Rights as a Customer". Cooperatives may use the title, "Your Rights as a Member".

(2) The information packet, containing the information required by this section, must be mailed to all customers on at least every other year at no charge to the customer.

(3) The information must be written in plain, non-technical language.

(4) The information must be provided in English and Spanish; however, an electric utility is exempt from the Spanish language requirement if 10% or fewer of its customers are exclusively Spanish-speaking. If the utility is exempt from the Spanish language requirement, it must notify all customers through a statement in both English and Spanish, in the packet, that the information is available in Spanish from the electric utility, both by mail and at the electric utility’s offices.

(5) The information packet must include all of the following:

(A) the customer’s right to information concerning rates and services and the customer’s right to inspect or obtain at reproduction cost a copy of the applicable tariffs and service rules;

(B) the electric utility's credit requirements and the circumstances under which a deposit or an additional deposit may be required, how a deposit is calculated, the interest paid on deposits, and the time frame and requirement for return of the deposit to the customer;

(C) the time allowed to pay outstanding bills;

(D) grounds for disconnection of service;

(E) the steps that must be taken before an electric utility may disconnect service;

(F) the steps for resolving billing disputes with the electric utility and how disputes affect disconnection of service;

(G) information on alternative payment plans offered by the electric utility, including, but not limited to, deferred payment plans, level billing programs, average payment plans, as well as a statement that a customer has the right to request these alternative payment plans;

(H) the steps necessary to have service reconnected after involuntary disconnection;

(I) the customer's right to file a complaint with the electric utility, the procedures for a supervisory review, and right to file a complaint with the commission, regarding any matter concerning the electric utility's service. The commission's contact information: Public Utility Commission of Texas, Office of Customer Protection, P.O. Box 13326, Austin, Texas 78711-3326, (512) 936-7120 or in Texas (toll-free) 1-888-782-8477, fax (512) 936-7003, e-mail address: customer@puc.state.tx.us,internet address: www.puc.state.tx.us, and Relay Texas (toll-free) 1-800-735-2989, must accompany this information;

(J) the hours, addresses, and telephone numbers of electric utility offices and any authorized locations where bills may be paid and information may be obtained or a toll-free telephone number that would provide the customer with this information;

(K) a toll-free telephone number or the equivalent (such as WATS or collect calls) where customers may call to report service problems or make billing inquiries;

(L) a statement that electric utility services are provided without discrimination as to a customer's race, color, sex, nationality, religion, or marital status, and a summary of the company's policy regarding the provision of credit history based upon the credit history of a customer's former spouse;

(M) notice of any special services such as readers or notices in Braille, if available, and the telephone number of the text telephone for the deaf at the commission;

(N) how customers with physical disabilities, and those who care for them, can identify themselves to the electric utility so that special action can be taken to inform these persons of their rights.

(O) the customer's right to have his or her meter tested without charge under §25.124 of this title (relating to Meter Testing);

(P) the customer's right to be instructed by the utility how to read his or her meter, if applicable;

(Q) a statement that funded financial assistance may be available for persons in need of assistance with their electric utility payments, and that additional information may be obtained by contacting the local office of the electric utility, Texas Department of Housing and Community Affairs, or the Public Utility

Commission of Texas. The main office telephone number (toll-free number, if available) and address for each state agency must also be provided; and

(R) information that explains how a residential customer can be recognized as a critical load customer, the benefits of being a critical load customer in an emergency situation, and the process for being placed on the critical load list. For the purposes of this section a "critical load residential customer" is defined as a residential customer who has a critical need for electric service because a resident on the premises requires electric service to maintain life.

§25.231. Cost of Service.

(a) **Components of cost of service.** Except as provided for in subsection (c)(2) of this section, relating to invested capital; rate base, and §23.23(b) of this title, (relating to Rate Design), rates are to be based upon an electric utility's cost of rendering service to the public during a historical test year, adjusted for known and measurable changes. The two components of cost of service are allowable expenses and return on invested capital.

(b) **Allowable expenses.** Only those expenses which are reasonable and necessary to provide service to the public will be included in allowable expenses. In computing an electric utility's allowable expenses, only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered, except as provided for in any section of these rules dealing with fuel expenses.

(1) **Components of allowable expenses.** Allowable expenses, to the extent they are reasonable and necessary, and subject to this section, may include, but are not limited to the following general categories:

(A) Operations and maintenance expense incurred in furnishing normal electric utility service and in maintaining electric utility plant used by and useful to the electric utility in providing such service to the public. Payments to affiliated interests for costs of service, or any property, right or thing, or for interest expense will not be allowed as an expense for cost of service except as provided in the Public Utility Regulatory Act §36.058.

(B) Depreciation expense based on original cost and computed on a straight line basis as approved by the commission. Other methods of depreciation may

be used when it is determined that such depreciation methodology is a more equitable means of recovering the cost of the plant.

(C) Assessments and taxes other than income taxes.

(D) Federal income taxes on a normalized basis. Federal income taxes must be computed according to the provisions of the Public Utility Regulatory Act §36.060.

(E) Advertising, contributions and donations. The actual expenditures for ordinary advertising, contributions, and donations may be allowed as a cost of service provided that the total sum of all such items allowed in the cost of service must not exceed three-tenths of 1.0% (0.3%) of the gross receipts of the electric utility for services rendered to the public. The following expenses must be included in the calculation of the three-tenths of 1.0% (0.3%) maximum:

(i) funds expended advertising methods of conserving energy;

(ii) funds expended advertising methods by which the consumer can effect a savings in total electric utility bills;

(iii) funds expended advertising methods to shift usage off of system peak; and

(iv) funds expended promoting renewable energy.

(F) Nuclear decommissioning expense. The following restrictions must apply to the inclusion of nuclear decommissioning costs that are placed in an electric utility's cost of service.

(i) An electric utility owning or leasing an interest in a nuclear-fueled generating unit must include its cost of nuclear decommissioning in its cost of service. Funds collected from ratepayers for decommissioning must be deposited monthly in irrevocable trusts external to the electric utility, in accordance with §25.301 of this title (relating to Nuclear Decommissioning Trusts). All funds held in short-term investments must bear interest. The level of the annual cost of decommissioning for ratemaking purposes will be determined in each rate case based on an allowance for contingencies of 10% of the cost of decommissioning, the most current information reasonably available regarding the cost of decommissioning, the balance of funds in the decommissioning trust, anticipated escalation rates, the anticipated return on the funds in the decommissioning trust, and other relevant factors. The annual amount for the cost of decommissioning determined pursuant to the preceding sentence must be expressly included in the cost of service established by the commission's order.

(ii) In the event that an electric utility implements an interim rate increase, including an increase filed under bond, an incremental change in decommissioning funding must be included in the increase.

(iii) An electric utility's decommissioning fund and trust balances will be reviewed in general rate cases. In the event that an electric utility

does not have a rate case within a five-year period, the commission, on its own motion or on the motion of commission staff, the Office of Public Utility Counsel, or any affected person, may initiate a proceeding to review the electric utility's decommissioning cost study and plan, and the balance of the trust.

(iv) An electric utility must perform, or cause to be performed, a study of the decommissioning costs of each nuclear generating unit that it owns or in which it leases an interest. A study or a redetermination of the previous study must be performed at least every five years. The study or redetermination should consider the most current information reasonably available on the cost of decommissioning. A copy of the study or redetermination must be filed with the commission and a copy provided to the Office of Public Utility Counsel. An electric utility's most recent decommissioning study or redeterminations must be filed with the commission within 30 days of the effective date of this subsection. The five-year requirement for a new study or redetermination must begin from the date of the last study or redetermination.

(G) Accruals credited to reserve accounts for self-insurance under a plan requested by an electric utility and approved by the commission. The commission may consider approval of a self insurance plan in a rate case in which expenses or rate base treatment are requested for a such a plan. For the purposes of this section, a self insurance plan is a plan providing for

accruals to be credited to reserve accounts. The reserve accounts are to be charged with property and liability losses which occur, and which could not have been reasonably anticipated and included in operating and maintenance expenses, and are not paid or reimbursed by commercial insurance. The commission will approve a self insurance plan to the extent it finds it to be in the public interest. In order to establish that the plan is in the public interest, the electric utility must present a cost benefit analysis performed by a qualified independent insurance consultant who demonstrates that, with consideration of all costs, self-insurance is a lower-cost alternative than commercial insurance and the ratepayers will receive the benefits of the self insurance plan. The cost benefit analysis must present a detailed analysis of the appropriate limits of self insurance, an analysis of the appropriate annual accruals to build a reserve account for self insurance, and the level at which further accruals should be decreased or terminated.

(H) Postretirement benefits other than pensions (known in the electric utility industry as "OPEB"). For ratemaking purposes, expense associated postretirement benefits other than pensions (OPEB) must be treated as follows:

(i) OPEB expense must be included in an electric utility’s cost of service for ratemaking purposes based on actual payments made.

(ii) An electric utility may request a one-time conversion to inclusion of current OPEB expense in cost of service for ratemaking purposes on

an accrual basis in accordance with generally accepted accounting principles (GAAP). Rate recognition of OPEB expense on an accrual basis must be made only in the context of a full rate case.

(iii) An electric utility will not be allowed to recover current OPEB expense on an accrual basis until GAAP requires that electric utility to report OPEB expense on an accrual basis.

(iv) For ratemaking purposes, the transition obligation must be amortized over 20 years.

(v) OPEB amounts included in rates must be placed in an irrevocable external trust fund dedicated to the payment of OPEB expenses. The trust must be established no later than six months after the order establishing the OPEB expense amount included in rates. The electric utility must make deposits to the fund at least once per year. Deposits on the fund must include, in addition to the amount included in rates, an amount equal to fund earnings that would have accrued if deposits had been made monthly. The funding requirement can be met with deposits made in advance of the recognition of the expense for ratemaking purposes. The electric utility must, to the extent permitted by the Internal Revenue Code, establish a postretirement benefit plan that allows for current federal income tax deductions for contributions and allows earnings on the trust funds to accumulate tax free.

(vi) When an electric utility terminates an OPEB trust fund established pursuant to clause (v) of this subparagraph, it must notify the commission in writing. If excess assets remain after the OPEB trust fund is terminated and all trust related liabilities are satisfied, the electric utility must file, for commission approval, a proposed plan for the distribution of the excess assets. The electric utility must not distribute any excess assets until the commission approves the disbursement plan.

(2) **Expenses not allowed.** The following expenses must never be allowed as a component of cost of service:

(A) legislative advocacy expenses, whether made directly or indirectly, including, but not limited to, legislative advocacy expenses included in professional or trade association dues;

(B) funds expended in support of political candidates;

(C) funds expended in support of any political movement;

(D) funds expended promoting political or religious causes;

(E) funds expended in support of or membership in social, recreational, fraternal, or religious clubs or organizations;

(F) funds promoting increased consumption of electricity;

(G) additional funds expended to mail any parcel or letter containing any of the items mentioned in subparagraphs (A)-(F) of this paragraph;

(H) payments, except those made under an insurance or risk-sharing arrangement executed before the date of the loss, made to cover costs of an

accident, equipment failure, or negligence at an electric utility facility owned by a person or governmental body not selling power within the State of Texas;

(I) costs, including, but not limited to, interest expense, of processing a refund or credit of sums collected in excess of the rate finally ordered by the commission in a case where the electric utility has put bonded rates into effect, or when the electric utility has otherwise been ordered to make refunds;

(J) any expenditure found by the commission to be unreasonable, unnecessary, or not in the public interest, including but not limited to executive salaries, advertising expenses, legal expenses, penalties and interest on overdue taxes, criminal penalties or fines, and civil penalties or fines.

(c) **Return on invested capital.** The return on invested capital is the rate of return times invested capital.

(1) **Rate of return.** The commission will allow each electric utility a reasonable opportunity to earn a reasonable rate of return, which is expressed as a percentage of invested capital, and will fix the rate of return in accordance with the following principles.

(A) The return should be reasonably sufficient to assure confidence in the financial soundness of the electric utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its

public duties. A rate of return may be reasonable at one time and become too high or too low because of changes affecting opportunities for investment, the money market, and business conditions generally.

(B) The commission will consider efforts by the electric utility to comply with the statewide integrated resource plan, the efforts and achievements of the electric utility in the conservation of resources, the quality of the electric utility's services, the efficiency of the electric utility's operations, and the quality of the electric utility's management, along with other applicable conditions and practices.

(C) The commission may, in addition, consider inflation, deflation, the growth rate of the service area, and the need for the electric utility to attract new capital. The rate of return must be high enough to attract necessary capital but need not go beyond that. In each case, the commission will consider the electric utility's cost of capital, which is the weighted average of the costs of the various classes of capital used by the electric utility.

(i) Debt capital. The cost of debt capital is the actual cost of debt at the time of issuance, plus adjustments for premiums, discounts, and refunding and issuance costs.

(ii) Equity capital. For companies with ownership expressed in terms of shares of stock, equity capital commonly consists of the following classes of stock.

(I) Common stock capital. The cost of common stock capital must be based upon a fair return on its market value.

(II) Preferred stock capital. The cost of preferred stock capital is the actual cost of preferred stock at the time of issuance, plus an adjustment for premiums, discounts, and refunding and issuance costs.

(2) **Invested capital; rate base.** The rate of return is applied to the rate base. The rate base, sometimes referred to as invested capital, includes as a major component the original cost of plant, property, and equipment, less accumulated depreciation, used and useful in rendering service to the public. Components to be included in determining the overall rate base are as set out in subparagraphs (A)-(F) of this paragraph.

(A) Original cost, less accumulated depreciation, of electric utility plant used by and useful to the electric utility in providing service.

(i) Original cost must be the actual money cost, or the actual money value of any consideration paid other than money, of the property at the time it would have been dedicated to public use, whether by the electric utility which is the present owner or by a predecessor.

(ii) Reserve for depreciation is the accumulation of recognized allocations of original cost, representing recovery of initial investment, over the estimated useful life of the asset. Depreciation must be computed on a straight line basis or by such other method approved under subsection (b)(1)(B) of this section over the expected useful life of the item or facility.

(iii) Payments to affiliated interests must not be allowed as a capital cost except as provided in the Public Utility Regulatory Act §36.058.

(B) Working capital allowance to be composed of, but not limited to the following:

(i) Reasonable inventories of materials, supplies, and fuel held specifically for purposes of permitting efficient operation of the electric utility in providing normal electric utility service. This amount excludes appliance inventories and inventories found by the commission to be unreasonable, excessive, or not in the public interest.

(ii) Reasonable prepayments for operating expenses. Prepayments to affiliated interests will be subject to the standards set forth in the Public Utility Regulatory §36.058.

(iii) A reasonable allowance for cash working capital. The following applies in determining the amount to be included in invested capital for cash working capital:

(I) Cash working capital for electric utilities must in no event be greater than one-eighth of total annual operations and maintenance expense, excluding amounts charged to operations and maintenance expense for materials, supplies, fuel, and prepayments.

(II) For electric cooperatives, river authorities, and investor-owned electric utilities that purchase 100% of their power

requirements, one-eighth of operations and maintenance expense excluding amounts charged to operations and maintenance expense for materials, supplies, fuel, and prepayments will be considered a reasonable allowance for cash working capital.

(III) Operations and maintenance expense does not include depreciation, other taxes, or federal income taxes, for purposes of subclauses (I), (II), and (V) of this clause.

(IV) For all investor-owned electric utilities a reasonable allowance for cash working capital, including a request of zero, will be determined by the use of a lead-lag study. A lead-lag study will be performed in accordance with the following criteria:

(-a-) The lead-lag study will use the cash method; all non-cash items, including but not limited to depreciation, amortization, deferred taxes, prepaid items, and return (including interest on long-term debt and dividends on preferred stock), will not be considered.

(-b-) Any reasonable sampling method that is shown to be unbiased may be used in performing the lead-lag study.

(-c-) The check clear date, or the invoice due date, whichever is later, will be used in calculating the

lead-lag days used in the study. In those cases where multiple due dates and payment terms are offered by vendors, the invoice due date is the date corresponding to the terms accepted by the electric utility.

(-d-) All funds received by the electric utility except electronic transfers must be considered available for use no later than the business day following the receipt of the funds in any repository of the electric utility (e.g. lockbox, post office box, branch office). All funds received by electronic transfer will be considered available the day of receipt.

(-e-) For electric utilities the balance of cash and working funds included in the working cash allowance calculation must consist of the average daily bank balance of all non-interest bearing demand deposits and working cash funds.

(-f-) The lead on federal income tax expense must be calculated by measurement of the interval between the mid-point of the annual service period and the actual payment date of the electric utility.

(-g-) If the cash working capital calculation results in a negative amount, the negative amount must be included in rate base.

(V) If cash working capital is required to be determined by the use of a lead-lag study under the previous subclause and either the electric utility does not file a lead lag study or the electric utility's lead-lag study is determined to be so flawed as to be unreliable, in the absence of persuasive evidence that suggests a different amount of cash working capital, an amount of cash working capital equal to negative one-eighth of operations and maintenance expense including fuel and purchased power will be presumed to be the reasonable level of cash working capital.

(C) Deduction of certain items which include, but are not limited to, the following:

(i) accumulated reserve for deferred federal income taxes;

(ii) unamortized investment tax credit to the extent allowed by the Internal Revenue Code;

(iii) contingency and/or property insurance reserves;

(iv) contributions in aid of construction;

(v) customer deposits and other sources of cost-free capital;

(D) Construction work in progress (CWIP). The inclusion of construction work in progress is an exceptional form of rate relief. Under ordinary

circumstances the rate base must consist only of those items which are used and useful in providing service to the public. Under exceptional circumstances, the commission will include construction work in progress in rate base to the extent that:

(i) the electric utility has proven that:

(I) the inclusion is necessary to the financial integrity of the electric utility; and

(II) major projects under construction have been efficiently and prudently planned and managed. However, construction work in progress must not be allowed for any portion of a major project which the electric utility has failed to prove was efficiently and prudently planned and managed; or

(ii) for a project ordered by the commission under §25.199 of this title (relating to Transmission Planning, Licensing and Cost-recovery for Utilities within the Electric Reliability Council of Texas), if the commission determines that conditions warrant the inclusion of CWIP in rate base, the project is being efficiently and prudently planned and managed, and there will be a significant delay between initial investment and the initial cost recovery for a transmission project.

(E) Self-insurance reserve accounts. If a self insurance plan is approved by the commission, any shortages to the reserve account will be an increase to the rate base and any surpluses will be a decrease to the rate base. The electric

utility must maintain appropriate books and records to permit the commission to properly review all charges to the reserve account and determine whether the charges being booked to the reserve account are reasonable and correct.

(F) Requirements for post test year adjustments.

(i) Post test year adjustments for known and measurable rate base additions (increases) to historical test year data will be considered only as set out in subclauses (I)-(IV) of this clause.

(I) Where the addition represents plant which would appropriately be recorded:

(-a-) for investor-owned electric utilities in FERC account 101 or 102;

(-b-) for electric cooperatives, the equivalent of FERC accounts 101 or 102.

(II) Where each addition comprises at least 10% of the electric utility's requested rate base, exclusive of post test year adjustments and CWIP.

(III) Where the plant addition is deemed by this commission to be in-service before the rate year begins.

(IV) Where the attendant impacts on all aspects of a utility's operations (including but not limited to, revenue, expenses and invested capital) can with reasonable certainty be identified, quantified and matched. Attendant impacts are

those that reasonably follow as a consequence of the post test year adjustment being proposed.

(ii) Each post test year plant adjustment will be included in rate base at:

(I) the reasonable test year-end CWIP balance, if the addition is constructed by the electric utility; or,

(II) the reasonable price, if the addition represents a purchase, subject to original cost requirements, as specified in Public Utility Regulatory Act §36.053.

(iii) Post test year adjustments for known and measurable rate base decreases to historical test year data will be allowed only when clause (i)(IV) of this subparagraph and the criteria described in subclauses (I) and (II) of this clause are satisfied.

(I) The decrease represents:

(-a-) plant which was appropriately recorded in the accounts set forth in clause (i)(I) of this subparagraph;

(-b-) plant held for future use;

(-c-) CWIP (mirror CWIP is not considered CWIP); or

(-d-) an attendant impact of another post test year adjustment.

(II) Plant that has been removed from service, mothballed, sold, or removed from the electric utility’s books prior to the rate year.

§25.238. Purchased Power Capacity Cost Recovery Factor (PCRF).

(a) **Application.** This section applies to an electric utility that sells electricity.

(b) **Definitions.** The following terms, when used in this section, have the following meanings unless the context indicates otherwise.

(1) **Class billing determinants** -- Kilowatt-hours (kWh) for each class that is not billed using a demand charge, and kilowatts (kW) for each class that is billed using a demand charge.

(2) **Cost year** -- the most recent historical 12-month period for which data are available at the time a utility prepares an application to establish, adjust, or terminate a PCRF.

(3) **Net production capacity invested capital** -- Production capacity invested capital costs recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 310 - 317, 320 - 326, 330 - 337, and 340 - 347, less accumulated depreciation and adjusted for any changes in production capacity-related accumulated deferred federal income taxes and excluding any impact associated with Financial Accounting Standards Board Interpretation No. 48.

(c) **Establishment, adjustment, and termination of a PCRF.**

(1) A utility may apply for establishment of a PCRF rider only if all of the following conditions are met:

(A) the utility's most recent comprehensive base-rate proceeding established sufficient information to allow for the determination of values for the parameters in subsection (h) of this section;

(B) no more than two years have passed since the final order in the utility's most recent comprehensive base-rate proceeding;

(C) the utility has not had a PCRF in effect within the last year; and

(D) no PCRF has been in effect for the utility since the final order in the utility's most recent comprehensive base-rate proceeding.

(2) The application in which the utility applies for the establishment, adjustment, or termination of a PCRF rider must be limited to issues related to the establishment, adjustment, or termination of the PCRF rider.

(3) The PCRF must not include:

(A) the cost of capacity purchased directly or indirectly from an affiliate, as defined in §25.5(3) of this title (relating to Definitions), of the utility, including, without limitation, whether such capacity is acquired through one or more intermediaries or pursuant to a FERC approved agreement or tariff of a Regional Transmission Organization or Independent System Operator, unless such affiliate-related purchases have been previously approved by the commission in a proceeding under subsection (d) of this section;

(B) the cost of capacity owned by the utility;

(C) any costs recoverable by the utility under §25.236 of this title (relating to Recovery of Fuel Costs), including purchases of firm energy;

(D) any costs for purchases made through day-ahead or real-time markets of a Regional Transmission Organization or Independent System Operator.

(4) Upon the establishment of a utility's PCRF, the utility must annually file an application for an adjustment of the PCRF. The cost year used in an annual PCRF

adjustment must be the 12-month period that immediately follows the cost year used to set the existing PCRF. In addition, the utility must file the application to adjust the PCRF promptly after the relevant cost-year data become available. The commission may establish a schedule for the filing of such applications.

(5) A utility may terminate its PCRF as part of any annual PCRF adjustment proceeding. The final order including the termination of a PCRF must specify the date by which the utility must be required to file an application for the final reconciliation of the costs and revenues associated with the terminated PCRF.

(6) Commission staff may petition at any time to terminate a utility's PCRF.

(7) A utility's request to establish, adjust, terminate, or reconcile a PCRF must include the utility's direct testimony supporting the request.

(d) **Pre-approval of purchased power agreements.**

(1) The commission may pre-approve a utility's executed agreement for the purchase of power capacity from an affiliate if it finds that the agreement is reasonable, and the utility may thereafter seek to include the capacity costs incurred under such a commission-approved agreement in its PCRF rider.

(2) Though not required for inclusion in a PCRF rider, a utility may seek commission review of the reasonableness of a utility's executed agreement for the purchase of power capacity from a non-affiliate, and the utility may seek to include the capacity costs incurred under such a commission-approved agreement in its PCRF rider.

(3) Agreements under paragraphs (1) and (2) of this subsection may include an agreement for the purchase of capacity to be delivered in the future that relies on the construction of a generating unit or units.

(4) An application in which the utility applies for pre-approval of purchased power capacity agreements under this subsection must be limited to issues related to the pre-approval of such agreements.

(5) A utility may apply for pre-approval of purchased power agreements under this subsection no more than once per year, and no more than three times between comprehensive base-rate proceedings.

(e) **Notice of PCRF proceeding.**

(1) Within one commission working day of filing an application limited to establishing, adjusting, or terminating a PCRF, a utility must provide notice of the application in accordance with the following:

(A) **Method of notice.**

(i) The utility must serve notice of the application on the parties to the utility's last PCRF reconciliation proceeding or, if there has been no PCRF reconciliation proceeding, on the parties to the utility's last comprehensive base-rate proceeding.

(ii) The utility must issue a news release and post the news release on its website.

(B) **Content of notice.** Notice provided pursuant to paragraph (1) of this subsection must include the following:

(i) The date the application was filed;

(ii) A description of the application, including the relief requested;

(iii) The date of the intervention and hearing request deadline. The date of the intervention and hearing request deadline must be 30 days after the application was filed, except that if the date would fall on a day that is not a commission working day, the intervention and hearing request deadline must be the first commission working day after the 30th day after the application was filed;

(iv) To the extent applicable, the existing PCRF and the proposed PCRF by rate class, and the percentage difference between the two;

(v) For an application seeking to establish or adjust a PCRF, the following statement: "The PCRF is subject to final review in the next PCRF reconciliation.";

(vi) The statement, "Persons with questions or who want more information on this application may contact (utility name) at (utility address) or call (utility toll-free telephone number) during normal business hours. A complete copy of this application is available for inspection at the address listed above"; and

(vii) The statement, "Persons who wish to intervene in the proceeding for this application, or who wish to provide their comments concerning this application, should contact the Public Utility Commission of Texas, Customer Protection Division, P.O. Box 13326, Austin, Texas 78711-3326, or call (512) 936-7120 or toll-free at (888) 782-

8477. Hearing and speech-impaired individuals may use Relay Texas (toll-free) 1-800-735-2989."

(C) **Proof of notice.** Within five commission working days from the filing of the application limited to establishing or adjusting a PCRF, the utility must file proof in the form of an affidavit that it complied with this paragraph.

(2) If a utility applies to reconcile a PCRF in a base-rate proceeding, the appropriate method and proof of notice set forth in §22.51 of this title (relating to Notice for Public Utility Regulatory Act, Chapter 36, Subchapters C-E; Chapter 51, §51.009; and Chapter 53, Subchapters C-E Proceedings) must apply. The notice must include a description of the requested change to the PCRF.

(3) If a utility applies to reconcile a PCRF outside of a base-rate proceeding, the method of notice set forth in §25.235(b)(1)(B) of this title (relating to Fuel Costs-General) applies. The proof of notice set forth in §25.235(b)(3) of this title must apply. The notice must include a description of the requested reconciliation of the PCRF.

(f) **Procedural schedule.** Upon the filing of an application limited to the annual adjustment of a PCRF pursuant to this section, the presiding officer must set a procedural schedule that will enable the commission to issue a final order in the proceeding as follows, except where good cause supports a different procedural schedule:

(1) within 60 days after a sufficient application was filed, if no hearing is requested within 30 days of the filing of the application; or

(2) within 120 days after a sufficient application was filed, if a hearing is requested within 30 days of the filing of the application. If a hearing is requested, the hearing

will be held no earlier than the first working day after the 45th day after a sufficient application was filed.

(g) **Exclusion from fuel factor.** Costs that are recovered through a PCRF must be excluded in calculating the utility's fixed fuel factor as defined in §25.237 of this title (relating to Fuel Factors).

(h) **PCRF formula.**

(1) The PCRF for each rate class must be calculated using the following formula:

$$\mathbf{PCRF = (\{(((PPC_{CY} + AAC_{CY} + APC_{M}) * TRAF_{CY}) - OSM_{CY}) * CAF_{CY}\} - \{(PPC_{RC\text{-}CLASS} + APC_{RC\text{-}CLASS} - OSM_{RC\text{-}CLASS}) * LGR\} - \{((PCIC_{RC\text{-}CLASS} * ROR_{AT}) + PCDEP_{RC\text{-}CLASS} + PCFIT_{RC\text{-}CLASS} + PCOT_{RC\text{-}CLASS}) * LGI\} + CTU) / CBD_{E}}$$

Where:

PPC_{CY} = Cost-year purchased power capacity costs from entities that are not affiliates, in accordance with subsection (c)(3) of this section.

AAC_{CY} = Cost-year purchased power capacity costs from entities that are affiliates and which costs are incurred from agreements that have been pre-approved by the commission in a proceeding under subsection (d) of this section as of the date of the filing of the instant PCRF application.

APC_{M} = The lesser of:

- purchased power capacity costs from affiliates used to set base rates in the utility's last comprehensive base-rate proceeding, or
- cost-year purchased power capacity costs from affiliates less AAC_{CY}.

OSM_{CY} = Cost-year margins from wholesale power capacity sales transactions.

$TRAF_{CY}$ = Cost-year value of the Texas retail jurisdiction production demand allocation factor, using the same type of production demand allocation factor used to set rates in the utility's last comprehensive base-rate proceeding.

CAF_{CY} = Cost-year value of the corresponding rate class production demand allocation factor, using the same type of production demand allocation factor used to set rates in the utility's last comprehensive base-rate proceeding.

$PPC_{RC\text{-}CLASS}$ = Purchased power capacity costs from entities that are not affiliates, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$APC_{RC\text{-}CLASS}$ = Purchased power capacity costs from affiliates allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$OSM_{RC\text{-}CLASS}$ = Margins from wholesale power capacity sales allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

LGR = The greater of (CBD_{CY} / CBD_{RC}) or 1.

CBD_{CY} = Cost-year rate class billing determinants.

CBD_{RC} = Rate class billing determinants used to calculate base rates from the utility's last comprehensive base-rate proceeding.

$PCIC_{RC\text{-}CLASS}$ = Net production capacity invested capital allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

ROR_{AT} = The after-tax rate of return used to set base rates from the utility's last comprehensive base-rate proceeding.

$PCDEP_{RC\text{-}CLASS}$ = Depreciation expense, as related to gross production capacity, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$PCFIT_{RC\text{-}CLASS}$ = Federal income tax, as related to net production capacity invested capital, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding.

$PCOT_{RC\text{-}CLASS}$ = Other taxes, as related to net production capacity invested capital, allocated to the rate class and used to set base rates from the utility's last comprehensive base-rate proceeding, and not including municipal franchise fees.

LGI = The greater of $((CBD_{CY} – CBD_{RC}) / CBD_{RC})$ or 0.

CTU = The rate class under/(over)-recovery, including interest, as calculated in subsection (i) of this section.

CBD_E = Estimated PCRF rate year class billing determinants.

(2) Where the cost year used in setting a PCRF includes a change in base rates due to a comprehensive base-rate proceeding, parameters in the PCRF formula that refer to values from the utility's last comprehensive base-rate proceeding must be calculated by prorating the values from the relevant base rate-proceedings across the cost-year.

(i) **True-up.** After establishment of an initial PCRF, a subsequent PCRF cost year is expected to contain portions of two different PCRF rate years. Therefore, for purposes of calculating class over- or under-recoveries for use in a proceeding to adjust the PCRF, previous PCRF revenue requirements from PCRF rate years in effect during the cost year must be prorated across the cost year. For each rate class, the difference between the prorated cost-year PCRF revenue requirement that previous PCRFs were set to recover from that class and the actual cost-year PCRF revenues recovered from that class, with interest on the balance calculated at the rate established annually by the commission pursuant to §25.28(c) and (d) of this title (relating to Bill Payment and Adjustments), must be credited or charged to that class when calculating the adjusted PCRF. In the event that a PCRF rider is terminated, any over- or under-recovery amounts, with interest applied, must be included in a separate rider.

(j) **Reconciliation of PCRF expenses.**

(1) The reasonableness and necessity of expenses recovered through the PCRF must be reviewed, and such costs and corresponding PCRF revenues must be reconciled, as part of any proceeding initiated under §25.236(b) of this title. Upon motion and showing of good cause, a PCRF reconciliation proceeding may be severed from or consolidated with other proceedings.

(2) In a proceeding in which PCRF costs are being reconciled, the electric utility has the burden of showing that:

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

(B) it has properly accounted for the amount of purchased power capacity-related revenues collected pursuant to the PCRF and corresponding to costs reviewed during the reconciliation period.

(3) Any refunds or surcharges resulting from a PCRF reconciliation, with interest applied, must, in the annual PCRF proceeding immediately subsequent to the filing of the final order in the reconciliation proceeding, be incorporated into the true-up balances described in subsection (i) of this section. In the event that no PCRF rider is in effect subsequent to a PCRF reconciliation, such refunds or surcharges, with interest applied, must be included in a separate rider.

(k) **Transition Issues.**

For a utility subject to a commission order to transition to retail competition as of the effective date of this section, the utility's existing power cost recovery factor in its tariff approved under the prior rule continues to be effective until the effective date of new unbundled retail delivery tariffs for the utility, at which time the power cost recovery factor must be terminated. Any over- or under-recovery amounts, with interest applied, must be included in a separate rider to the utility's retail delivery tariffs to be established in the proceeding that approves such tariffs and must be credited or charged to customers as appropriate. The utility must file monthly reports with the commission showing all such

amounts until no remaining amounts remain to be credited or charged, at which time the utility must file a final report with the commission.

§25.240. Contribution Disclosure Statements in Appeals of Municipal Utility Rates.

(a) **Pursuant to Chapter 33, Subchapter D.** Each party to an appeal proceeding under the Public Utility Regulatory Act (PURA), Chapter 33, Subchapter D must file a statement with the commission disclosing all expenditures made by that party and all contributions made to that party, whether the expenditures or contributions are financial or in-kind, related to preparation of and filing of a petition for appeal, the preparation of expert testimony, and legal representation in the proceeding. The municipality whose rates are the subject of the appeal, commission staff, and the Office of Public Utility Counsel are not required to file a statement. The statement must list with particularity the name and address of each contributor and provide a description of each contribution. The statement will be available to the public. The statement must be filed within 30 days after a final appealable order is entered by the commission or the petition of appeal is withdrawn.

(b) **Pursuant to PURA §33.123.** Any party that brings an appeal under PURA §33.123 (appellant) must file within 30 days after filing the appeal with the commission and within each 30 days thereafter, a statement that discloses with particularity each and every contribution, whether financial or in-kind, made to the appellant in support of the appeal. This obligation will continue until a statement is filed that includes all contributions made up until the commission has entered a final appealable order. The statement will list the name and address of each contributor and provide a description of each contribution.

(c) **Hearings on statements.** Upon motion by any party or upon the commission's own motion, the commission may conduct a hearing on the statements to make such determinations as may be necessary under PURA, Chapter 33, Subchapter D or §33.123.

§25.271. Foreign Utility Company Ownership by Exempt Holding Companies.

(a) **Certification to Securities and Exchange Commission.** Upon request by a holding company which is exempt under §3 of the Public Utility Holding Company Act of 1935, codified at 15 United States Code 79, the commission may certify to the Securities and Exchange Commission (SEC) that the commission has the authority and resources to protect ratepayers and that it intends to exercise its authority over holding companies owning both a jurisdictional electric utility and a foreign utility company (FUCO) under the safe harbor provisions of subsection (c) of this section or the case-by-case review provisions of subsection (d) of this section. The commission may also notify the SEC that a previously-issued certification regarding a requesting holding company will be ineffective prospectively.

(b) **Policy goals.** The commission will seek to protect the public interest in having electricity service available to all citizens of the state at just, fair, and reasonable rates that are unaffected by investments by exempt holding companies in foreign utility companies (FUCOs), while avoiding strictures that would place exempt holding companies at a competitive disadvantage in international markets. The commission will consider these policy goals in each decision whether to issue a certification or to notify the SEC that a previously-issued certification is prospectively withdrawn.

(c) **Safe harbor investments.** The following safe harbor provisions apply to investments in FUCOs by exempt holding companies that are affiliated with electric utilities subject to the regulatory jurisdiction of the commission:

(1) The commission must certify to the SEC that the commission has the authority and resources to protect ratepayers subject to its jurisdiction and that it intends to exercise its authority, provided that all holding companies of electric utilities that are subject to the regulatory jurisdiction of this commission must have filed with the commission corporate undertakings, signed under oath by an authorized executive officer of the holding company agreeing to adhere to the covenants and to make the filings specified in paragraph (2) of this subsection.

(2) The holding company must adhere to the following covenants:

(A) That any indebtedness incurred in relation to the acquisition by the holding company, or by any affiliate of the electric utility, of an ownership interest in a FUCO will be without recourse to the electric utility;

(B) That the electric utility, the holding company, or any affiliate of the electric utility will not enter into any agreements under the terms of which the electric utility is obligated to commit funds in order to maintain the financial viability of a FUCO or an affiliate of the electric utility investing in a FUCO;

(C) That the electric utility will not provide, directly or indirectly, any guarantees or other forms of credit support for any funds borrowed by the holding company or an affiliate of the electric utility in connection with the acquisition of any ownership interest in a FUCO;

(D) That the electric utility, the holding company, or any affiliate of the electric utility will not make any investment in a FUCO under circumstances in which the electric utility would be liable for the debts and/or liabilities of the FUCO incurred as a result of acts or omissions of the FUCO;

(E) That the electric utility will maintain and provide a copy to the commission of its accounting policies and procedures that assure that the electric utility is adequately and fairly compensated by the holding company or an affiliate of the electric utility for any use of the electric utility's assets or personnel in furtherance of a FUCO;

(F) That the holding company provides the commission reasonable access to books and records and financial statements, or copies thereof, of the FUCO or other affiliate doing business with the FUCO, in English and stated in United States dollars, as the commission may request to:

(i) review transactions between the electric utility and such FUCO or affiliate pursuant to the Public Utility Regulatory Act §14.154; and

(ii) review transactions between any affiliate and the FUCO if such affiliate also has transactions directly or indirectly with the electric utility;

(G) That the holding company will file with the commission quarterly a report listing the total amount of the aggregate investments by the holding company and its subsidiaries and the percentage of the holding company's consolidated net worth, from the company's most recent SEC form 10-Q, represented by such investments;

(i) "Aggregate investment" means all amounts invested, or committed to be invested, in exempt wholesale generators located outside the United States (foreign EWGs) and FUCOs, for which there is recourse, directly or indirectly, to the holding company. Among other things, the term must include preliminary development expenses that culminate in the acquisition of a foreign EWG or a FUCO.

(ii) Such report must be filed no later than ten days following the filing of the 10-Q for the quarter.

(H) That in the event the holding company anticipates making any investment in a FUCO that would result in the aggregate investment as defined in subparagraph (G) of this paragraph of such holding company exceeding 30% of the consolidated net worth of such holding company, the holding company must so advise the commission before a final commitment to ownership of such FUCO is made;

(I) That the electric utility will provide, by March 31 of each year, a copy of the electric utility's three-year cash flow forecast;

(J) That the holding company will provide to the commission all SEC forms for reporting information related to foreign EWG and FUCO investments, no later than ten days after such forms are provided to the SEC;

(K) That the holding company will promptly notify the commission whenever any of the following occurs:

(i) It is unable to provide the certifications, undertakings, or documents provided for in this paragraph;

(ii) The aggregate investment exceeds 30% of consolidated net worth;

(iii) The holding company's operating losses attributable to its direct or indirect investments in foreign EWGs and FUCOs exceeded 5.0% of consolidated retained earnings during the previous four quarters; and

(L) That the holding company will comply with the informational filing requirements of subsection (d) of this section in connection with a contemplated investment in

a FUCO, unless the commission finds good cause not to require the holding company to provide such additional information.

(d) **Other investments.** For any occasion for which a holding company has undertaken to notify the commission of an event specified in subsection (c)(2)(H) or (K) of this section, the following provisions apply:

(1) The holding company must provide the following information, to the extent such information is reasonably available at the time of submission of the filing, at least 30 days before the date when it anticipates making a final commitment to ownership of a FUCO not already covered by a certification letter:

(A) A description of the proposed investment, including a description of the FUCO assets being acquired, their geographical location, the form of the investment (partnership, joint venture, direct purchase, etc.), the holding company's percentage share of the investment, a description of how the investment will fit into the corporate subsidiary structure, and any other information reasonably necessary in the opinion of the holding company to provide a complete overview of the nature of the proposed investment;

(B) Any financial requirements and/or commitments by the holding company or the electric utility that will be made or assumed as a result of this investment; this information should include, but is not limited to, an estimate of the amount of equity capital to be invested;

(C) Any debt obligations resulting from this investment which will provide recourse to the holding company or the electric utility;

(D) The holding company's general corporate objectives regarding diversification and foreign utility investments, and the specific objectives of the proposed FUCO investment;

(E) A statement that the electric utility has effective written policies and accounting procedures which insure that any use by the FUCO of assets or personnel of an affiliate of the electric utility, or other transactions between the FUCO and an affiliate of the electric utility will not negatively affect Texas ratepayers; and a statement that the electric utility will demonstrate in each subsequent rate proceeding before the commission, and each subsequent audit, that no FUCO investment increased the cost of capital or revenue requirement of the electric utility;

(F) A calculation, based on the holding company's most recent SEC Form 10-Q, of aggregate consolidated holding company investments as defined in subsection (c)(2)(G) of this section as a percentage of consolidated holding company net worth, stated both before and after all asset transfers from any affiliate of the electric utility to FUCOs at fair market value;

(G) A statement that the holding company will provide to the commission all SEC forms for reporting information related to foreign EWG and FUCO investments, no later than ten days after such forms are provided to the SEC; and

(H) Responses to questions, if any, contained on a commission prescribed form.

(2) The notification prescribed in this subsection may be submitted less than 30 days before the date when the holding company anticipates making a final commitment to ownership of a FUCO not already covered by a certification letter upon a

showing of good cause. Good cause for purposes of the preceding sentence must be deemed to include, without limitation, a representation that the holding company lacked the information required to make a submission at an earlier date or a representation that making the submission at an earlier date would have unreasonably jeopardized the ability of the holding company to go forward with the contemplated investment.

(3) In its review of the information provided pursuant to this section, the commission will consider, among other things, the number and magnitude of prior FUCO investments by the holding company, including the diversity among the countries in which such investments are located and other differences between such investments, and the magnitude of the proposed investment and its effect on the diversity of the portfolio.

(e) **Post-investment reporting**. The electric utility must comply with the following post-investment reporting obligations:

(1) With respect to any investment in a FUCO for which an informational filing was made pursuant to subsection (d)(1) of this section, the electric utility or holding company must notify the commission no later than ten days after the holding company makes a final commitment to ownership of a FUCO that such a commitment has been made. Such notice must include any material corrections, additions, and supplementation of previously-provided information; and

(2) For any FUCO investment covered by a certification, the electric utility or holding company must notify the commission no later than 30 days after any material change in the circumstances or nature of an investment in a FUCO. Such notice must include all appropriate corrections, additions, and supplementation of

previously-provided information. A material change would include, but is not limited to, any change that would have an adverse impact of greater than 1.0% of consolidated net worth most recently reported; full or partial divestiture of the investment; a catastrophic event that destroys a significant amount of FUCO property or results in loss of life that could result in a significant liability claim; a change in the laws or government policy having a material impact on the FUCO; or an event which would place a significant restriction on the repatriation of earnings of the FUCO.

(3) Unless included in SEC reports, each exempt utility holding company which directly or indirectly holds an interest in FUCOs or foreign EWGs must provide the following information: A consolidating statement of income of the exempt holding company and its subsidiary companies for the last calendar year, together with a consolidating balance sheet of the exempt holding company and its subsidiary companies as of the close of such calendar year.

(A) The information must be provided in English, monetary amounts in U.S. dollars, and according to generally accepted accounting principles.

(B) Such information must be received by the commission annually no later than March 15.

(f) **Commission standards for granting or maintaining certification.**

(1) In general, the commission will issue and continue certification when the aggregate investment in FUCOs and foreign EWGs is less than 30% of the holding company's

consolidated net worth, and the company has satisfactorily provided the information and assurances set out in the preceding subsections.

(2) With respect to any investment in a FUCO for which an informational filing was made pursuant to subsection (d)(1) of this section, the commission must determine on a case-by-case basis whether to issue a certification to the SEC or maintain a previously issued certification. The commission must endeavor to make such a determination prior to the date when the holding company anticipates having to make a final commitment to ownership of the FUCO. If the commission determines that it does not intend to continue certification, it may inform the SEC that maintaining a previously-issued certification would be inappropriate.

(3) The commission must notify the holding company requesting the certification or retention of certification of its decision within 45 days of receiving the request. If no action is taken by the commission within 45 days of receiving the request, the certification is deemed granted or affirmed.

(4) Any information submitted by a holding company pursuant to this section may be submitted by the holding company under seal. Each page tendered under seal must have the words "Confidential Information" typed or stamped on its face. The holding company must clearly identify each portion of the application alleged to be Confidential Information; identify the exemption to the Public Information Act, Texas Government Code Annotated, Chapter 552 (Vernon Supp. 1998), applicable to the alleged Confidential Information; and provide a detailed explanation of why the alleged Confidential Information is exempt from public disclosure under the Public Information Act. If the commission receives a Public Information Act request for

disclosure of Confidential Information, then the Executive Director must promptly so notify the holding company. The Executive Director must timely request an Attorney General's opinion as to whether the information falls within any of the exemptions identified in Subchapter C of the Public Information Act. The Executive Director must promptly provide to the holding company a copy of an Attorney General opinion regarding the claim of confidentiality. If an Attorney General opinion recommends disclosure of Confidential Information, either in whole or in part, then the Executive Director must not release such information for ten calendar days, in order to allow the holding company time to pursue any legal remedies that it may have. The holding company may require the execution of an appropriate confidentiality agreement prior to providing access to such confidential information to commission staff or any other interested party. The form of any such confidentiality agreement must be approved by commission staff legal counsel prior to filing and included with the informational filing.

§25.301. Nuclear Decommissioning Trusts.

(a) **Duties of electric utilities.**

(1) Each electric utility collecting funds for a nuclear decommissioning trust must assure that the nuclear decommissioning trust is managed so that the funds are secure and earn a reasonable return; and, that the funds provided from the utility's cost of service, plus the amounts earned from investment of the funds, will be available at the time of decommissioning.

(2) Each electric utility collecting funds for a nuclear decommissioning trust must place the funds in an external, irrevocable trust fund. The utility must appoint an institutional trustee and may appoint an investment manager(s). Unless otherwise specified in subsection (b) of this section, the Texas Trust Code controls the administration and management of the nuclear decommissioning trusts, except that the appointed trustee(s) need not be qualified to exercise trust powers in Texas.

(3) The utility must retain the right to replace the trustee with or without cause. In appointing a trustee, the electric utility must have the following duties, which will be of a continuing nature:

(A) A duty to determine whether the trustee's fee schedule for administering the trust is reasonable, when compared to other institutional trustees rendering similar services, and meets the requirement of subsection (c)(2)(A) of this section;

(B) A duty to investigate and determine whether the past administration of trusts by the trustee has been reasonable;

(C) A duty to investigate and determine whether the financial stability and strength of the trustee is adequate;

(D) A duty to investigate and determine whether the trustee has complied with the trust agreement and this section as it relates to trustees; and,

(E) A duty to investigate any other factors which may bear on whether the trustee is suitable.

(4) The utility must retain the right to replace the investment manager with or without cause. In appointing an investment manager, the utility must have the following duties, which will be of a continuing nature:

(A) A duty to determine whether the investment manager's fee schedule for investment management services is reasonable, when compared to other such managers, and meets the requirement of subsection (c)(2)(A) of this section;

(B) A duty to investigate and determine whether the past performance of the investment manager in managing investments has been reasonable;

(C) A duty to investigate and determine whether the financial stability and strength of the investment manager is adequate for purposes of liability;

(D) A duty to investigate and determine whether the investment manager has complied with the investment management agreement and this section as it relates to investments; and,

(E) A duty to investigate any other factors which may bear on whether the investment manager is suitable.

(b) **Agreements between the electric utility and the institutional trustee or investment manager.**

(1) The utility must execute an agreement with the institutional trustee. The agreement must include the restrictions in subparagraphs (A) - (E) of this paragraph and may include additional restrictions on the trustee. An electric utility must not grant the trustee powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section.

(A) The interest earned on the corpus of the trust becomes part of the trust corpus. A trustee owes the same duties with regard to the interest earned on the corpus as are owed with regard to the corpus of the trust.

(B) A trustee must have a continuing duty to review the trust portfolio for compliance with investment guidelines and governing regulations.

(C) A trustee must not lend funds from the decommissioning trust with itself, its officers, or its directors.

(D) A trustee must not invest or reinvest decommissioning trust funds in instruments issued by the trustee, except for time deposits, demand deposits, or money market accounts of the trustee. However, investments of a decommissioning trust may include mutual funds that contain securities issued by the trustee if the securities of the trustee constitute no more than five percent of the fair market value of the assets of such mutual funds at the time of the investment.

(E) The agreement must comply with all applicable requirements of the Nuclear Regulatory Commission.

(2) The utility must execute an agreement with the investment manager. (If the trustee performs investment management functions, the contractual provisions governing those functions must be included in either the trust agreement or a separate investment management agreement.) The agreement must include the restrictions set forth in subparagraphs (A) - (E) of this paragraph and may include additional restrictions on the manager. An electric utility must not grant the manager powers that are greater than those provided to trustees under the Texas Trust Code or that are inconsistent with the limitations of this section.

(A) An investment manager must, in investing and reinvesting the funds in the trust, comply with subsection (c) of this section.

(B) The interest earned on the corpus of the trust becomes part of the trust corpus. An investment manager owes the same duties with regard to the interest earned on the corpus as are owed with regard to the corpus of the trust.

(C) An investment manager must have a continuing duty to review the trust portfolio to determine the appropriateness of the investments.

(D) An investment manager must not invest funds from the decommissioning trust with itself, its officers, or its directors.

(E) The agreement must comply with all applicable requirements of the Nuclear Regulatory Commission.

(3) A copy of the trust agreement, any investment management agreement, and any amendments must be filed with the commission within 30 days after the execution or modification of the agreement, and copies provided to the commission’s Legal

Division and Rate Regulation Division and the Office of Public Utility Counsel. All previously executed agreements and amendments must be filed within 30 days of the effective date of this section.

(4) Within 90 days after the effective date of this section, a utility that is a party to a trust agreement or an investment management agreement that is not in compliance with this section must revise the agreement to comply with this section.

(c) **Trust investments.**

(1) **Investment portfolio goals.** The funds should be invested consistent with the following goals. The utility may apply additional prudent investment goals to the funds so long as they are not inconsistent with the stated goals of this subsection.

(A) The funds should be invested with a goal of earning a reasonable return commensurate with the need to preserve the value of the assets of the trusts.

(B) In keeping with prudent investment practices, the portfolio of securities held in the decommissioning trust must be diversified to the extent reasonably feasible given the size of the trust.

(C) Asset allocation and the acceptable risk level of the portfolio should take into account market conditions, the time horizon remaining before the commencement and completion of decommissioning, and the funding status of the trust. While maintaining an acceptable risk level consistent with the goal in subparagraph (A) of this paragraph, the investment emphasis when the remaining life of the liability, as defined in paragraph (2)(F)(iv) of this subsection, exceeds five years should be to maximize net long-term earnings. The investment emphasis in the

remaining investment period of the trust should be on current income and the preservation of the fund's assets.

(D) In selecting investments, the impact of the investment on the portfolio's volatility and expected return net of fees, commissions, expenses and taxes should be considered.

(2) **General requirements.** The following requirements must apply to all decommissioning trusts. Where a utility has multiple trusts for a single generating unit, the restrictions contained in this subsection apply to all trusts in the aggregate for that generating unit. For purposes of this section, a commingled fund is defined as a professionally managed investment fund of fixed-income or equity securities established by an investment company regulated by the Securities Exchange Commission or a bank regulated by the Office of the Comptroller of the Currency.

(A) Fees limitation. The total trustee and investment manager fees paid on an annual basis by the utility for the entire portfolio including commingled funds must not exceed 0.7% of the entire portfolio's average annual balance.

(B) Diversification. For the purpose of this subparagraph, a commingled or mutual fund is not considered a security; rather, the diversification standard applies to all securities, including the individual securities held in commingled or mutual funds. Once the portfolio of securities (including commingled funds) held in the decommissioning trust(s) contains securities with an aggregate value in excess of $20 million, it must be diversified such that:

(i) no more than 5.0 % of the securities held may be issued by one entity, with the exception of the federal government, its agencies and instrumentalities, and;

(ii) the portfolio must contain at least 20 different issues of securities. Municipal securities and real estate investments must be diversified as to geographic region.

(C) Qualified trusts. The utility may invest the decommissioning funds by means of qualified or unqualified nuclear decommissioning trusts; however, the utility must, to the extent permitted by the Internal Revenue Service, invest its decommissioning funds in "qualified" nuclear decommissioning trusts, in accordance with the Internal Revenue Service Code §468A.

(D) Derivatives. The use of derivative securities in the trust is limited to those whose purpose is to enhance returns of the trust without a corresponding increase in risk or to reduce risk of the portfolio. Derivatives may not be used to increase the value of the portfolio by any amount greater than the value of the underlying securities. Prohibited derivative securities include, but are not limited to, mortgage strips; inverse floating rate securities; leveraged investments or internally leveraged securities; residual and support tranches of Collateralized Mortgage Obligations; tiered index bonds or other structured notes whose return characteristics are tied to non-market events; uncovered call/put options; large counter-party risk through over-the-counter options, forwards and swaps; and instruments with similar high-risk characteristics.

(E) The use of leverage (borrowing) to purchase securities or the purchase of securities on margin for the trust is prohibited.

(F) Investment limits in equity securities. The following investment limits must apply to the percentage of the aggregate market value of all non-fixed income investments relative to the total portfolio market value.

(i) Except as noted in clause (ii), when the weighted average remaining life of the liability exceeds 5 years, the equity cap is 60%;

(ii) When the weighted average remaining life of the liability ranges between 5 years and 2.5 years, the equity cap must be 30%. Additionally, during all years in which expenditures for decommissioning the nuclear units occur, the equity cap must also be 30%;

(iii) When the weighted average remaining life of the liability is less than 2.5 years, the equity cap must be 0%;

(iv) For purposes of this subparagraph, the weighted average remaining life in any given year is defined as the weighted average of years between the given year and the years of each decommissioning outlay, where the weights are based on each year's expected decommissioning expenditures divided by the amount of the remaining liability in that year; and

(v) Should the market value of non-fixed income investments, measured monthly, exceed the appropriate cap due to market fluctuations, the utility must, as soon as practicable, reduce the market value of the non-fixed income investments below the cap. Such reductions may be accomplished by investing all future contributions to the fund in debt securities as is

necessary to reduce the market value of the non-fixed income investments below the cap, or if prudent, by the sale of equity securities.

(G) A decommissioning trust must not invest in securities issued by the electric utility collecting the funds or any of its affiliates; however, investments of a decommissioning trust may include commingled funds that contain securities issued by the electric utility if the securities of the utility constitute no more than 5.0% of the fair market value of the assets of such commingled funds at the time of the investment.

(3) **Specific investment restrictions.** The following restrictions must apply to all decommissioning trusts. Where a utility has multiple trusts for a single generating unit, the restrictions contained in this subsection apply to all trusts in the aggregate for that generating unit.

(A) Fixed-income investments. A decommissioning trust must not invest trust funds in corporate or municipal debt securities that have a bond rating below investment grade (below "BBB-" by Standard and Poor's Corporation or "Baa3" by Moody's Investor's Service) at the time that the securities are purchased and must reexamine the appropriateness of continuing to hold a particular debt security if the debt rating of the company in question falls below investment grade at some time after the debt security has been purchased. Commingled funds may contain some below investment grade bonds; however, the overall portfolio of debt instruments must have a quality level, measured quarterly, not below a "AA" grade by Standard and Poor's Corporation or "Aa2" by Moody's Investor's

Service. In calculating the quality of the overall portfolio, debt securities issued by the federal government must be considered as having a "AAA" rating.

(B) Equity investments.

(i) At least 70% of the aggregate market value of the equity portfolio, including the individual securities in commingled funds, must have a quality ranking from a major rating service such as the earnings and dividend ranking for common stock by Standard and Poor's or the quality rating of Ford Investor Services. Further, the overall portfolio of ranked equities must have a weighted average quality rating equivalent to the composite rating of the Standard and Poor's 500 index assuming equal weighting of each ranked security in the index. If the quality rating, measured quarterly, falls below the minimum quality standard, the utility must as soon as practicable and prudent to do so, increase the quality level of the equity portfolio to the required level.

(ii) A decommissioning trust must not invest in equity securities where the issuer has a capitalization of less than $100 million.

(C) Commingled funds. The following guidelines must apply to the investments made through commingled funds. Examples of commingled funds appropriate for investment by nuclear decommissioning trust funds include United States equity-indexed funds, actively managed United States equity funds, balanced funds, bond funds, real estate investment trusts, and international funds.

(i) The commingled funds should be selected consistent with the goals specified in paragraph (1) and the requirements in paragraph (2) of this subsection.

(ii) In evaluating the appropriateness of a particular commingled fund, the utility has the following duties, which must be of a continuing nature:

(I) A duty to determine whether the fund manager's fee schedule for managing the fund is reasonable, when compared to fee schedules of other such managers;

(II) A duty to investigate and determine whether the past performance of the investment manager in managing the commingled fund has been reasonable relative to prudent investment and utility decommissioning trust practices and standards; and

(III) A duty to investigate the reasonableness of the net after-tax return and risk of the fund relative to similar funds, and the appropriateness of the fund within the entire decommissioning trust investment portfolio.

(iii) The payment of load fees must be avoided.

(iv) Commingled funds focused on specific market sectors or concentrated in a few holdings must be used only as necessary to balance the trust's overall investment portfolio mix.

§25.483. Disconnection of Service.

(a) **Disconnection and reconnection policy**. Only a transmission and distribution utility (TDU), municipally owned utility, or electric cooperative may perform physical disconnections and reconnections. Unless otherwise stated, it is the responsibility of a retail electric provider (REP) to request such action from the appropriate TDU, municipally owned utility, or electric cooperative in accordance with that entity's relevant tariffs, in accordance with the protocols established by the registration agent, and in compliance with the requirements of this section. If a REP chooses to have a customer's electric service disconnected, it must comply with the requirements in this section. Nothing in this section requires a REP to request that a customer's service be disconnected.

(b) **Disconnection authority.**

(1) Any REP may authorize the disconnection of a medium non-residential or large non-residential customer, as that term is defined in §25.43 of this title (relating to Provider of Last Resort (POLR)).

(2) Except as provided in subsection (d) of this section, all REPs mayauthorize the disconnection of residential and small non-residential customers pursuant to commission rules. Prior to authorizing disconnections for non-payment in accordance with this paragraph, a REP must:

(A) test all necessary electronic transactions related to disconnections and reconnections of service; and

(B) file an affidavit from an officer of the company, in a project established by the commission for this purpose, affirming that the REP understands and

has trained its personnel on the commission's rule requirements related to disconnection and reconnection, and has adequately tested the transactions described in subparagraph (A) of this paragraph.

(c) **Disconnection with notice**. A REP having disconnection authority under the provisions of subsection (b) of this section, including the POLR, may authorize the disconnection of a customer's electric service after proper notice and not before the first day after the disconnection date in the notice for any of the following reasons:

(1) failure to pay any outstanding bona fide debt for electric service owed to the REP or to make deferred payment arrangements by the date of disconnection stated on the disconnection notice. Payment of the delinquent bill at the REP's authorized payment agency is considered payment to the REP;

(2) failure to comply with the terms of a deferred payment agreement made with the REP;

(3) violation of the REP's terms and conditions on using service in a manner that interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;

(4) failure to pay a deposit as required by §25.478 of this title (relating to Credit Requirements and Deposits); or

(5) failure of the guarantor to pay the amount guaranteed, when the REP has a written agreement, signed by the guarantor, which allows for disconnection of the guarantor's service.

(d) **Disconnection without prior notice**. Any REP or TDU may, at any time, authorize disconnection of a customer's electric service without prior notice for any of the following reasons:

(1) Where a known dangerous condition exists for as long as the condition exists. Where reasonable, given the nature of the hazardous condition, the REP or its agent must post a notice of disconnection and the reason for the disconnection at the place of common entry or upon the front door of each affected residential unit as soon as possible after service has been disconnected;

(2) Where service is connected without authority by a person who has not made application for service;

(3) Where service is reconnected without authority after disconnection for nonpayment;

(4) Where there has been tampering with the equipment of the transmission and distribution utility, municipally owned utility, or electric cooperative; or

(5) Where there is evidence of theft of service.

(e) **Disconnection prohibited**. A REP having disconnection authority under the provisions of subsection (b) of this section must not authorize a disconnection for nonpayment of a customer's electric service for any of the following reasons:

(1) Delinquency in payment for electric service by a previous occupant of the premises;

(2) Failure to pay for any charge that is not for electric service regulated by the commission, including competitive energy service, merchandise, or optional services;

(3) Failure to pay for a different type or class of electric service unless charges for such service were included on that account's bill at the time service was initiated;

(4) Failure to pay charges resulting from an underbilling, except theft of service, more than six months prior to the current billing;

(5) Failure to pay disputed charges, except for the amount not under dispute, until a determination as to the accuracy of the charges has been made by the REP or the commission, and the customer has been notified of this determination;

(6) Failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due under §25.126 of this title (relating to Adjustments Due to Non-Compliant Meters and Meter Tampering in Areas Where Customer Choice Has Been Introduced); or

(7) Failure to pay an estimated bill other than a bill rendered pursuant to an approved meter-reading plan, unless the bill is based on an estimated meter read by the TDU.

(f) **Disconnection on holidays or weekends.**

(1) A REP having disconnection authority under the provisions of subsection (b) of this section must not request disconnection of a customer's electric service for nonpayment on a holiday or weekend, or the day immediately preceding a holiday

or weekend, unless the REP's personnel are available on those days to take payments, make payment arrangements with the customer, and request reconnection of service.

(2) Unless a dangerous condition exists or the customer requests disconnection, a TDU must not disconnect a customer's electric service on a holiday or weekend, or the day immediately preceding a holiday or weekend, unless the personnel of the TDU are available to reconnect service on all of those days.

(g) **Disconnection of Critical Care Residential Customers**. A REP having disconnection authority under the provisions of subsection (b) of this section must not authorize a disconnection for nonpayment of electric service at a permanent, individually metered dwelling unit of a delinquent Critical Care Residential Customer when that customer establishes that disconnection of service will cause some person at that residence to become seriously ill or more seriously ill.

(1) Each time a Critical Care Residential Customer seeks to avoid disconnection of service under this subsection, the customer must accomplish all of the following by the stated date of disconnection:

(A) Have the person's attending physician (for purposes of this subsection, the "physician" means any public health official, including medical doctors, doctors of osteopathy, nurse practitioners, registered nurses, and any other similar medical professional) contact the REP to confirm that the customer is a Critical Care Residential Customer;

(B) Have the person's attending physician submit a written statement to the REP confirming that the customer is a Critical Care Residential Customer; and

(C) Enter into a deferred payment plan.

(2) The prohibition against service disconnection of a Critical Care Residential Customer provided by this subsection lasts 63 days from the issuance of the bill for electric service or a shorter period agreed upon by the REP and the customer, emergency (secondary) contact listed on the commission-approved application form, or attending physician. If the Critical Care Residential Customer does not accomplish the requirements of paragraph (1) of this subsection:

(A) The REP must provide written notice to the Critical Care Residential Customer and the emergency contact listed on the commission-approved application form of its intention to disconnect service not later than 21 days prior to the date that service would be disconnected. Such notice must be a separate mailing or hand delivered notice with a stated date of disconnection with the words "disconnection notice" or similar language prominently displayed. If the REP has offered and the customer has agreed for the customer and/or emergency contact to receive disconnection notices from the REP by email, a separate email with the words "disconnection notice" or similar language in the subject line must be sent in addition to the separate mailing or hand delivered notice. Except as provided in this subsection, the notice must comply with the requirements of subsections (l) and (m) of this section; and

(B) Prior to disconnecting a Critical Care Residential Customer, a TDU must contact the customer and the emergency contact listed on the commission-approved application form. If the TDU does not reach the customer and emergency contact by phone, the TDU must visit the premises, and, if there is no response, must leave a door hanger containing the pending disconnection information and information on how to contact the REP and TDU.

(3) If, in the normal performance of its duties, a TDU obtains information that a customer scheduled for disconnection may qualify for delay of disconnection pursuant to this subsection, and the TDU reasonably believes that the information may be unknown to the REP, the TDU must delay the disconnection and promptly communicate the information to the REP. The TDU must disconnect such customer if it subsequently receives a confirmation of the disconnect notice from the REP. Nothing herein should be interpreted as requiring a TDU to assess or to inquire as to the customer's status before performing a disconnection when not otherwise required.

(4) If a TDU refuses to disconnect a Critical Care Residential Customer pursuant to this subsection, it must cease charging all transmission and distribution charges and surcharges, except securitization-related charges, for that premises to the REP.

(h) **Disconnection of Chronic Condition Residential Customers.** A REP having disconnection authority under the provisions of subsection (b) of this section must not authorize a disconnection for nonpayment of electric service at a permanent, individually

metered dwelling unit of a delinquent customer when that customer has been designated as a Chronic Condition Residential Customer pursuant to §25.497 of this title (relating to Critical Load Industrial Customers, Critical Load Public Safety Customers, Critical Care Residential Customers, and Chronic Condition Residential Customers), except as provided in this subsection. The REP must notify the Chronic Condition Residential Customer and the emergency contact listed on the commission-approved application form with a written notice of its intention to disconnect service not later than 21 days prior to the date that service would be disconnected. Such notice must be a separate mailing or hand delivered notice with a stated date of disconnection with the words "disconnection notice" or similar language prominently displayed. If the REP has offered and the customer has agreed for the customer and/or emergency contact to receive disconnection notices from the REP by email, a separate email with the words "disconnection notice" or similar language in the subject line must be also be sent in addition to the separate mailing or hand delivered notice. Except as provided in this subsection, the notice must comply with the requirements of subsections (l) and (m) of this section.

(i) **Disconnection of energy assistance clients**.

(1) A REP having disconnection authority under the provisions of subsection (b) of this section must not authorize a disconnection for nonpayment of electric service to a delinquent residential customer for a billing period in which the REP receives a pledge, letter of intent, purchase order, or other notification that the energy assistance provider is forwarding sufficient payment to continue service provided that such pledge, letter of intent, purchase order, or other notification is received by

the due date stated on the disconnection notice, and the customer, by the due date on the disconnection notice, either pays or makes payment arrangements to pay any outstanding debt not covered by the energy assistance provider.

(2) If an energy assistance provider has requested monthly usage data pursuant to §25.472(b)(4) of this title (relating to Privacy of Customer Information), the REP must extend the final due date on the disconnection notice, day for day, from the date the usage data was requested until it is provided.

(3) A REP must allow at least 45 days for an energy assistance provider to honor a pledge, letter of intent, purchase order, or other notification before submitting the disconnection request to the TDU.

(4) A REP may request disconnection of service to a customer if payment from the energy assistance provider's pledge is not received within the time frame agreed to by the REP and the energy assistance provider, or if the customer fails to pay any portion of the outstanding balance not covered by the pledge.

(j) **Disconnection during extreme weather**. A REP having disconnection authority under the provisions of subsection (b) of this section must not authorize a disconnection for nonpayment of electric service for any customer in a county in which an extreme weather emergency occurs. A REP must offer residential customers a deferred payment plan upon request by the customer that complies with the requirements of §25.480 of this title (relating to Bill Payment and Adjustments) for bills that become due during the weather emergency.

(1) The term "extreme weather emergency" means a day when:

(A) the previous day's highest temperature did not exceed 32 degrees Fahrenheit, and the temperature is predicted to remain at or below that level for the next 24 hours anywhere in the county, according to the nearest National Weather Service (NWS) reports; or

(B) the NWS issues a heat advisory for a county, or when such advisory has been issued on any one of the preceding two calendar days in a county.

(2) A TDU must notify the commission of an extreme weather emergency in a method prescribed by the commission, on each day that the TDU has determined that an extreme weather emergency has been issued for a county in its service area. The initial notice must include the county in which the extreme weather emergency occurred and the name and telephone number of the utility contact person.

(k) **Disconnection of master-metered apartments**. When a bill for electric service is delinquent for a master-metered apartment complex:

(1) The REP having disconnection authority under the provisions of subsection (b) of this section must send a notice to the customer as required by this subsection. At the time such notice is issued, the REP, or its agents, must also inform the customer that notice of possible disconnection will be provided to the tenants of the apartment complex in six days if payment is not made before that time.

(2) At least six days after providing notice to the customer and at least four days before disconnecting, the REP must post a minimum of five notices in English and Spanish in conspicuous areas in the corridors or other public places of the apartment complex. Language in the notice must be in large type and must read: "Notice to

residents of (name and address of apartment complex): Electric service to this apartment complex is scheduled for disconnection on (date), because (reason for disconnection)."

(l) **Disconnection notices**. A disconnection notice for nonpayment must:

(1) not be issued before the first day after the bill is due;

(2) be a separate mailing or hand delivered notice with a stated date of disconnection with the words "disconnection notice" or similar language prominently displayed or, if the REP has offered and the customer has agreed to receive disconnection notices from the REP by email, be a separate email with the words "disconnection notice" or similar language in the subject line. The REP may send the disconnection notice concurrently with the request for a deposit;

(3) have a disconnection date that is not a holiday, weekend day, or day that the REP's personnel are not available to take payments, and is not less than ten days after the notice is issued; and

(4) include a statement notifying the customer that if the customer needs assistance paying the bill by the due date, or is ill and unable to pay the bill, the customer may be able to make some alternate payment arrangement, establish a deferred payment plan, or possibly secure payment assistance. The notice must also advise the customer to contact the provider for more information.

(m) **Contents of disconnection notice**. Any disconnection notice must include the following information:

(1) The reason for disconnection;

(2) The actions, if any, that the customer may take to avoid disconnection of service;

(3) The amount of all fees or charges which will be assessed against the customer as a result of the default;

(4) The amount overdue;

(5) A toll-free telephone number that the customer can use to contact the REP to discuss the notice of disconnection or to file a complaint with the REP, and the following statement: "If you are not satisfied with our response to your inquiry or complaint, you may file a complaint by calling or writing the Public Utility Commission of Texas, P.O. Box 13326, Austin, Texas, 78711-3326; Telephone: (512) 936-7120 or toll-free in Texas at (888) 782-8477. Hearing and speech impaired individuals may contact the commission through Relay Texas at 1-800-735-2989. Complaints may also be filed electronically at www.puc.texas.gov/ocp/complaints/complain.cfm;"

(6) If a deposit is being held by the REP on behalf of the customer, a statement that the deposit will be applied against the final bill (if applicable) and the remaining deposit will be either returned to the customer or transferred to the new REP, at the customer's designation and with the consent of both REPs;

(7) The availability of deferred payment or other billing arrangements, from the REP, and the availability of any state or federal energy assistance programs and information on how to get further information about those programs; and

(8) A description of the activities that the REP will use to collect payment, including the use of consumer reporting agencies, debt collection agencies, small claims

court, and other remedies allowed by law, if the customer does not pay or make acceptable payment arrangements with the REP.

(n) **Reconnection of service.** Upon a customer's satisfactory correction of the reasons for disconnection, the REP must request the TDU, municipally owned utility, or electric cooperative to reconnect the customer's electric service as quickly as possible. The REP must inform the customer when reconnection is expected to occur in accordance with the timelines set forth in this subsection and in §25.214 of this title (relating to Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities). For premises without a provisioned advanced meter with remote disconnect/reconnect capabilities, if a REP submits a standard reconnect request and the TDU completes the reconnect the same day, the TDU may assess a standard reconnect fee. A TDU may assess a same-day reconnect fee only when the REP expressly requests a same-day reconnect and a REP may pass through a same-day reconnect fee to the customer only when the customer expressly requests a same-day reconnect. A REP must send a reconnection request no later than the timelines in this subsection. The TDU must complete the reconnection in accordance with the timelines in §25.214 of this title.

(1) For payments made before 12:00 p.m. on a business day, a REP must send a reconnection request to the TDU no later than 2:00 p.m. on the same day.

(2) For payments made after 12:00 p.m. but before 5:00 p.m. on a business day, a REP must send a reconnection request to the TDU by 7:00 p.m. on the same day.

(3) For payments made after 5:00 p.m. but before 7:00 p.m. on a business day, a REP must send a reconnection request to the TDU by 9:00 p.m. on the same day.

(4) For payments made after 7:00 p.m. on a business day, a REP must send a reconnection request to the TDU by 2:00 p.m. on the next business day.

(5) For payments made on a weekend day or a holiday, a REP must send a reconnection request to the TDU by 2:00 p.m. on the first business day after the payment was made.

(6) In no event must a REP fail to send a reconnection notice within 48 hours after the customer's satisfactory correction of the reasons for disconnection as specified in the disconnection notice.

(o) **Electric service disconnection of a non-submetered master metered multifamily property**.

(1) In this subsection, "non-submetered master metered multifamily property" means an apartment, a leased or owner-occupied condominium, or one or more buildings containing at least 10 dwellings that receive electric utility service that is master metered but not submetered.

(2) A REP must send a written notice of service disconnection to a municipality before authorizing disconnection of service to a non-submetered master metered multifamily property for nonpayment if:

(A) the property is located in the municipality; and

(B) the municipality establishes an authorized representative to receive the notice as described by paragraph (3) of this subsection.

(3) No later than January 1st of every year, a municipality wishing to receive notice of disconnection of electric service to a non-submetered master metered multifamily

property must provide the commission with the contact information for the municipality's authorized representative referenced by paragraph (2) of this subsection by submitting that person's name, title, direct mailing address, telephone number, and email address in a P.U.C. Project Number to be established annually for that purpose. The email address provided by the municipality may be for a general mailbox accessible by the authorized representative established for the purpose of receiving such notices.

(4) After January 1st, but no later than January 15th of every year, the commission must post on its public website the contact information received from every municipality pursuant to paragraph (3) of this subsection. The contact information posted by the commission must remain in effect during the subsequent 12-month period of February 1 through January 31 for the purpose of the written notice of disconnection required by paragraph (2) of this subsection.

(5) The retail electric provider must email the written notice required by this subsection to the municipality's authorized representative not later than the 10th day before the date electric service is scheduled for disconnection. Additional notice may be provided by third-party commercial carrier delivery or certified mail.

(6) The customer safeguards provided by this subchapter are in addition to safeguards provided by other law or agency rules.

(7) This subsection does not prohibit a municipality or the commission from adopting customer safeguards that exceed the safeguards provided by this chapter.

§25.486 Customer Protections for Brokerage Services.

(a) **Applicability.** This section applies to all brokers.

(b) **Definitions.** The following terms, when used in this section, have the following meanings unless the context indicates otherwise:

(1) **Broker** -- As defined in §25.112 of this title (relating to Registration of Brokers).

(2) **Brokerage services** -- As defined in §25.112 of this title.

(3) **Client** -- A person who receives or solicits brokerage services from a broker.

(4) **Client agent** -- A broker who has the legal right and authority to act on behalf of a client regarding the selection of, enrollment for, or contract execution of a product or service offered by a retail electric provider (REP), including electric service.

(5) **Proprietary client information** -- Any information that is compiled by a broker on a client or retail electric customer that makes possible the identification of any individual client or retail electric customer by matching such information with the client's or customer's name, address, retail electric account number, type or classification of retail electric service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual retail electric or brokerage services contract terms and conditions, price, current charges, billing records, or any information that the client or customer has expressly requested not be disclosed. Information that is redacted or organized in

such a way as to make it impossible to identify the client or customer to whom the information relates does not constitute proprietary client information.

(c) **Voluntary Alteration of Customer Protections**. A client other than a residential or small commercial class customer or applicant, or a non-residential customer or applicant whose load is part of an aggregation in excess of 50 kilowatts, may agree to a different level of customer protections related to the provision of brokerage services than is required by this section. Any such agreements do not change the level of customer protections a client is entitled to relating to the provision of retail electric service. Any agreements containing a different level of protections from those required by this section must be in writing and provided to the client. Copies of such agreements must be provided to commission staff upon request.

(d) **Broker Communications**.

(1) All written, electronic, and oral communications, including advertising, websites, direct marketing materials, and billing statements produced by a broker must be clear and not misleading, fraudulent, unfair, deceptive, or anti-competitive. Prohibited communications include, but are not limited to:

(A) Stating, suggesting, implying or otherwise leading a client to believe that receiving brokerage services will provide a customer with more reliable service from a transmission and distribution utility (TDU);

(B) Falsely suggesting, implying or otherwise leading a client to believe that a person is a representative of a TDU, REP, aggregator, or another broker;

(C) Falsely stating or suggesting that brokerage services are being provided without compensation; and

(D) Falsely claiming to be the client agent of a customer or applicant.

(2) All printed advertisements, electronic advertising over the Internet, and websites must include the broker's registered name.

(e) **Language Requirements.** A broker must offer customer service and any information required by this section to a client in the language used to market the broker's products and services to that client.

(f) **Required Disclosures**. A broker must inform a client of the following prior to the initiation of brokerage services, the renewal of those services, or a material change in the services provided, or the terms and conditions of those services:

(1) The broker's registered name, business mailing address, and contact information;

(2) The broker's commission registration number;

(3) The registered name of any REP that is an affiliate of the broker;

(4) A clear description of the services the broker will provide for the client.

(5) The duration of the agreement to provide brokerage services, if applicable;

(6) A description of how the broker will be compensated for providing brokerage services and by whom;

(7) How the client can terminate the agreement to provide brokerage services, if applicable;

(8) The amount of any fee or other cost the client will incur for terminating the agreement to provide brokerage services, if applicable; and

(9) The commission's telephone number and email address for complaints and inquiries.

(g) **Client Agent Requirements.**

(1) An agreement between a broker and a client that authorizes the broker to act as a client agent for the client must be in writing.

(2) In addition to the requirements of subsection (f) of this section, a broker that acts as a client agent for the client must inform the client of the following:

(A) A clear description of the actions the broker is authorized to take on the client's behalf;

(B) The duration of the agency relationship;

(C) How the client can terminate the agency agreement;

(D) The amount of any fee or other cost the client will incur for terminating the agency agreement; and

(E) How the client's customer data, including proprietary client information, and account access information will be used, protected, and retained by the broker and disposed of at the conclusion of the agency relationship.

(3) A broker that is authorized to act as a client agent for the client must provide evidence of that authority upon request of the client, commission staff, or a REP with which the broker seeks to enroll the client.

(4) For purposes of §25.474 of this title (relating to Selection of Retail Electric Provider), a REP may rely upon the representations made by a client agent provided that the client agent is registered with the commission and provides evidence of agency authority.

(h) **Unauthorized Charges and Unauthorized Changes of Retail Electric Provider.**

(1) Unauthorized charges. A broker must not bill an unauthorized charge or cause an unauthorized charge to be billed to a customer's retail electric service bill.

(2) Unauthorized service changes. A broker must not switch or cause to be switched the REP of a customer without first obtaining the customer's authorization.

(i) **Discrimination Prohibited.** A broker must not unduly refuse to provide brokerage services or otherwise unduly discriminate in the provision of brokerage services to any client because of race, creed, color, national origin, ancestry, sex, marital status, source or level of income, disability, or familial status; or refuse to provide brokerage services to a client because the client is located in an economically distressed geographic area or qualifies for low-income affordability or energy efficiency services; or otherwise unreasonably discriminate on the basis of the geographic location of a client.

(j) **Proprietary Client Information.**

(1) A broker must not release proprietary client information to any person unless the client authorizes the release in writing. This prohibition does not apply to the release of such information to the commission.

(2) A broker is not permitted to sell, make available for sale, or authorize the sale of any client-specific information or data obtained unless the client authorizes the sale in writing.

(k) **Client Access and Complaint Handling.**

(1) **Client Access.** Each broker must ensure that clients have reasonable access to its service representatives to make inquiries and complaints, discuss charges on bills or any other aspect of the brokerage services provided to the client by the broker, terminate an agreement to provide services, and transact any other pertinent business. A broker must promptly investigate client complaints and advise the complainant of the results. A broker must inform the complainant of the commission's informal complaint resolution process and the following contact information for the commission within 21 days of receiving the complaint: Public Utility Commission of Texas, Customer Protection Division, P.O. Box 13326, Austin, Texas 78711-3326; (512) 936-7120 or in Texas (toll-free) 1-888-782-8477, fax (512) 936-7003, e-mail address: customer@puc.texas.gov, Internet website address: www.puc.texas.gov, and Relay Texas (toll-free) 1-800-735-2989.

(2) **Complaint Handling**. A client has the right to make a formal or informal complaint to the commission. A broker may not use a written or verbal agreement with a client to impair this right for a client that is a residential or small commercial customer. A broker must not require a client that is a residential or small commercial customer to engage in alternative dispute resolution, including requiring complaints to be submitted to arbitration or mediation by third parties.

(3) **Informal Complaints**.

(A) A person may file an informal complaint with the commission by contacting the commission at: Public Utility Commission of Texas, Customer Protection Division, P.O. Box 13326, Austin, Texas 78711-3326; (512) 936-7120 or in Texas (toll-free) 1-888-782-8477, fax (512) 936-7003, e-mail address: customer@puc.texas.gov, Internet website address: www.puc.texas.gov, and Relay Texas (toll-free) 1-800-735-2989.

(B) A complaint should include the following information, as applicable:

(i) The complainant's name, billing and service address, telephone number and email address, if any;

(ii) The name of the broker;

(iii) The broker's registration number;

(iv) The name of any relevant REP;

(v) The customer account number or electric service identifier;

(vi) An explanation of the facts relevant to the complaint;

(vii) The complainant's requested resolution; and

(viii) Any documentation that supports the complaint.

(C) The commission will forward the informal complaint to the broker.

(D) The broker must investigate each informal complaint forwarded to the broker by the commission and advise the commission in writing of the results of the investigation within 21 days after the complaint is forwarded to the broker by the commission.

(E) The commission will review the complaint information and the broker's response and notify the complainant of the results of the commission's investigation.

(F) The broker must keep a record for two years after receiving notification by the commission that the complaint has been closed. This record must show the name and address of the complainant, the date, nature, and outcome of the complaint.

(G) While an informal complaint process is pending, the broker must not initiate collection activities, including a report of the customer's delinquency to a credit reporting agency, with respect to the disputed portion of the bill.

(4) **Formal Complaints.** If the complainant is not satisfied with the results of the informal complaint process, the complainant may file a formal complaint with the commission within two years of the date on which the commission closes the informal complaint. Formal complaints will be docketed as provided in the commission's procedural rules.

(l) **Record Retention.**

(1) A broker must establish and maintain records and data that are sufficient to:

(A) Verify its compliance with the requirements of any applicable commission rules; and

(B) Support any investigation of customer complaints.

(2) All records required by this section must be retained for no less than two years, unless otherwise specified.

(3) Unless otherwise prescribed by the commission or its authorized representative, all records required by this subchapter must be provided to the commission within 15 calendar days of its request.

This agency 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 the amendments to §§25.31 relating to Information to Applicants and Customers, 25.238, relating to Purchased Power Capacity Cost Recovery Factor (PCRF); 25.240, relating to Contribution Disclosure Statements in Appeals of Municipal Utility Rates, 25.271, relating to Foreign Utility Company Ownership by Exempt Holding Companies, 25.301, relating to Nuclear Decommissioning Trusts; 25.483, relating to Disconnection of Service, and 25.486, relating to Customer Protections for Brokerage Services are hereby adopted with no changes to the text as proposed. Amendments to §25.231 are hereby adopted with changes to the text as proposed.

Signed at Austin, Texas the _____ day of JUNE 2023.

PUBLIC UTILITY COMMISSION OF TEXAS

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KATHLEEN JACKSON, INTERIM CHAIR

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WILL MCADAMS, COMMISSIONER

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JIMMY GLOTFELTY, COMMISSIONER