The Public Utility Commission of Texas (commission) adopts new §25.173 relating to Goal for Renewable Energy with changes to the proposed text as published in the October 22, 1999 issue of the *Texas Register* (24 TexReg 9142). This section is adopted under Project Number 20944. Section 25.173 will implement the legislative goal for renewable energy development in the state of Texas as set forth in Senate Bill 7 (SB 7), Act of May 21, 1999, 76th Legislature, Regular Session, chapter 405, 1999 Texas Session Law Service 2543, 2561 (Vernon) (to be codified as an amendment to the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §39.904).

In adopting this rule, the commission's objective is to establish a renewable energy credits trading program (trading program) and define the renewable energy purchase requirements for competitive retailers in Texas. This rule will (1) implement the statutory mandate in PURA §39.904 to promote the development of renewable energy technologies; (2) encourage the construction and operation of new renewable energy projects at those sites in Texas that have the greatest potential for capture and development of environmentally beneficial renewable resources; (3) reduce air pollution in Texas that is associated with the generation of electricity using fossil fuels; (4) respond to customer preferences that place a high value on environmental quality and reflect a willingness to pay a higher price for "clean" energy acquired from renewable resources; (5) increase the amount of renewable energy available to supply electricity to consumers in Texas; and (6) ensure that all customers have access to energy from renewable energy resources pursuant to PURA §39.101(b)(3).

Texas possesses a vast amount of untapped renewable resources, perhaps more than any other state. The Legislature recognized that economic and environmental benefits would accrue to Texas citizens from the development of those resources by enacting §39.904, which mandates that an additional 2,000 megawatts (MW) of generating capacity from renewable technologies be installed in Texas by January 1, 2009.

The Legislature's commitment to development of the state's abundant renewable resources is derived from the preferences expressed by Texas consumers in favor of renewable power. The integrated resource planning process required that utilities assess customer values and preferences and consider these preferences in their resource plans. In an effort to assess customer values and preferences, utilities across the state polled their customers. Statistically significant samples representing about two-thirds of retail electric customers in Texas indicated a willingness to purchase electricity that was generated by renewable energy resources to improve air quality in their communities and across the state. The customers' preferences, revealed in the polling process, are reflected in PURA §39.904: cleaner sources of energy should be deployed to develop the state's renewable resources and improve the quality of the air in Texas.

Texas has long been a leader in the direct use of energy produced by burning fossil fuels. Although Texas has historically been one of the largest energy consumers in the nation, it has continued to be near the bottom in the production and use of renewable energy. The continued growth of the Texas economy and population will continue to make it one of the leaders in energy consumption. Relying on energy produced by burning fossil fuels has contributed to the degradation of air quality in much of Texas, and reliance on fossil-fueled energy sources in the future will continue this trend. Texas electric customers have placed a high value on environmental quality and have shown a willingness to pay a premium for clean energy sources that benefit their communities and the state of Texas. The renewable energy mandate, coupled with the program for trading renewable energy credits (RECs), will ensure prudent use of clean, abundant, and unused Texas renewable resources in the energy production process in a least-cost manner. Additionally, it allows renewable industry participants from Texas or any other location to compete in a market for renewable energy.

The staff held a public workshop to begin the evaluation of issues related to the renewable energy mandate. During this workshop, a technical taskforce with four working groups was formed to address key issues. Six subsequent task force meetings were held during which stakeholders participated in painstaking negotiations to develop a well-balanced rule to implement the requirements of PURA §39.904. The rule reflects the work products of the task force and working groups, incorporating numerous compromises reached by parties in the technical workshops conducted in this proceeding. Where consensus could not be reached, staff considered all views presented in the workshops and in written comments in drafting the proposed rule, which was approved for publication on October 6, 1999.

On November 5, 8, and 10, the following parties filed comments on the proposal: Automated Power Exchange (APX), Guadalupe Blanco River Authority (GBRA), City Public Service of San Antonio (CPS), Entergy Gulf States (EGS), Public Utilities Board of Brownsville (PUB), Texas Industrial Energy Consumers (TIEC), TXU Electric (TXU), Lower Colorado River Authority (LCRA), Texas Renewable Energy Industries Association (TREIA), Shell Energy Services Company, L.L.C. (Shell), Duke Solar Energy and The Boeing Company (Duke Solar and Boeing), the City of Denton, the City of Garland, and the Greenville Electric Utility System (the Cities), Reliant Energy HL&P (Reliant), Texas-New Mexico Power Company (TNMP), Enron, Sabine River Authority of Texas (SRAT), Southwestern Public Service Company (SPS), South Texas Electric Cooperative (STEC), Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities Company, which are the Texas operating companies of Central and Southwest Corporation (collectively, CSW), Environmental Defense Fund (EDF), Austin Energy, East Texas Cooperatives (ETC), Office of Public Utility Counsel and Cities served by CP&L and TXU (OPC and Cities), Texas Electric Cooperatives (TEC), Brazos Electric Power Cooperative and Rayburn Country Electric Cooperative (Brazos and Rayburn), Texas Renewable Power Coalition (Renewable Coalition or The Coalition), Small Hydro of Texas (Small Hydro), and the Texas Public Power Association (TPPA).

On November 22, 1999, commission staff held a public hearing pursuant to §2001.029 of the Administrative Procedure Act. Representatives Leo Berman, Jim McReynolds, Bob Glaze, Tom Ramsay and Senator Bill Ratliff attended the hearing and provided comments regarding the treatment of existing resources in the proposed rule. ETC, SPS, and the Cities also provided oral comments on the proposed section. Any comments provided at the public hearing that were not previously submitted in written comments during this proceeding are summarized herein.

In general, Austin Energy, CSW, Enron, Small Hydro, EGS, Reliant, Duke Solar and Boeing, TREIA, EDF, and the Renewable Coalition complimented the commission and staff for using a consensus-based process involving all interested parties to define the principal elements of the trading program. EDF noted that this proceeding was unlike any other, requiring parties new to this concept to think in new ways about regulatory programs. EDF also commented that the rule as published is exceptional and that Texas is clearly in the position of producing a rule that can serve as a model for other states. Shell Energy commended the commission staff for their work on an extraordinarily difficult rulemaking, stating that the proposed rule undoubtedly will further renewable energy capacity development in Texas. The Renewable Coalition commended the commission and staff for publishing a rule that promises to efficiently achieve the principal goal for renewable energy established by the Legislature. Reliant generally supported the proposed rule as published, while STEC stated that it exceeds the commission's statutory authority, is anti-competitive, discriminatory, and unconstitutional.

Comments on specific questions in the preamble to the proposed rule

In the preamble, the commission sought comment on the penalty provisions set forth in §25.173(n). Parties were asked whether meaningful penalties are necessary to ensure compliance with the trading program requirements and to provide examples of penalty provisions contained in other trading programs such as the Acid Rain Program administered by the Environmental Protection Agency (EPA). Parties were also asked to comment on appropriate monetary fees for penalties assessed to competitive retailers participating in the trading program.

Most of the parties agreed that meaningful penalties were necessary; however, TNMP commented that penalties should not be assessed for competitive retailers who fail to meet their allocation of RECs. TNMP contended that there is no need for a standard dollar per megawatt-hour (MWh) penalty or a penalty based on a percentage of market value. TNMP suggested that a competitive retailer should have until March 31 of each year to make up any deficit of RECs through transactions on the open market.

The Cities commented that the administrative penalty provisions of PURA §15.023 are not applicable to municipally owned utilities or electric cooperatives, because §15.023 is applicable to a "person" regulated under PURA. Municipally owned utilities and electric cooperatives are not within the definition of "person" in PURA §11.003. TXU contended that all trading program participants must be treated equally and should therefore be subject to penalties. TXU proposed adopting a provision stating that an electric cooperative or municipality that opts in to customer choice and participation in the REC trading program thereby voluntarily submits itself to the administrative penalty provisions of PURA §15.023 and the proposed rule with respect to its obligations under PURA §39.904.

Duke Energy, TIEC, TREIA, EDF, CSW, Reliant, TXU, and OPC & Cities generally agreed that the penalty structure proposed in the rule was appropriate. Austin Energy and the Coalition commented that the penalties were not strong enough. Austin Energy recommended that in addition to a monetary penalty, the retail electric provider should also be required to purchase the additional deficit credits. The Coalition likewise commented that the penalty amount should be higher to ensure that the cost of non-compliance is higher than the cost of compliance. Shell, Reliant, TXU, and CSW disagreed with this position.

Shell, TXU, STEC, Entergy, Enron, OPC, and TEC recommended various penalty structure solutions. Shell commented that the proposed fixed penalty scheme violates PURA §15.023(c), which requires the commission to take into account six factors in determining an appropriate penalty amount and that the commission should delete subsection (n)(2) and follow the statutory scheme, using a case-by-case evaluation. If the commission establishes a penalty mechanism, however, Shell suggested that the commission modify the penalty scheme to allow competitive retailers to earn back the penalty through future superior performance, and that the commission preserve the option to assess an appropriate penalty, based on the circumstances. The Coalition disagreed with Shell on this point. Shell also suggested that the commission consider waiving penalties altogether if the year's statewide capacity goal is met. Shell contended that the $50 per MWh penalty exceeds the tolerance margin for non-affiliate retail electric providers (REPs), and that the commission should set penalties only after it knows the prevailing REC market value during the compliance period.

Shell recommended that the commission incorporate a market value, using a two-prong penalty measure. Shell relied on a penalty proposed in an Arizona rulemaking. Shell recommended that the penalty be the lesser of $30 per MWh or the Texas average annual firm peak MWh price during the compliance period. The $30 per MWh penalty would constitute a ceiling, with the penalty otherwise determined according to the prevailing market price. With respect to penalties assessed according to the average market value of credits, Shell contended that the commission can not determine market value unless parties disclose all trade prices to the program administrator. The Renewable Coalition pointed out that the penalty proposed in Arizona is not $30 per MWh, but rather $0.30 per kilowatt-hour (kWh) or $300 per MWh. The Coalition concluded that the Texas penalty is therefore significantly less costly than the Arizona penalty.

TXU commented that $50 per MWh is an inappropriate penalty figure. TXU argued that the monetary penalty should be set not at the total cost of a MWh of renewable energy, but at some multiple of the differential in price between market and renewable energy. TXU further commented that assuming that the market value of credits will reflect the cost differential between renewable power and market power, a reasonable penalty is some multiple of the market value of credits. TXU also suggested graduated penalty provisions. TXU maintained that it is reasonable to base the penalty on the average market value of credits even though price is not required to be reported in connection with the transfer of RECs, because it is anticipated that the necessary pricing information will be readily obtainable. TEC disagreed with TXU's proposal that penalties be assessed on a dollar per MW basis for failure to have sufficient renewable capacity under contract by January 1, 2003. Such penalties would be duplicative of penalties for failure to satisfy the energy-based renewable requirement for 2003. TEC contended such double penalties would be unreasonably punitive. TEC noted that competitive retailers will likely satisfy their renewable obligations through the purchase of RECs instead of contracting for renewable capacity directly, and should not be penalized for failure to contract for the capacity. TEC noted that electric cooperatives that are parties to an all-requirements contract would be precluded from contracting for renewable capacity and that penalties for failure to contract for capacity would discourage such electric cooperatives from offering customer choice until some time after the capacity penalties no longer apply, and capacity penalties would fail to recognize that retail load obligations will change during 2003. TEC observed that this would have the discriminatory effect of subjecting incumbent suppliers to capacity-based penalties, but not new retail suppliers. STEC and Enron agreed that a competitive retailer should not be penalized when it has made a good faith effort to comply with its REC allocation. STEC also urged the commission to modify the penalty provision to incorporate the language suggested by TEC that would expressly exempt competitive retailers from penalties resulting from shortfalls in the renewable energy supplied by the seller of renewables.

Enron and EGS commented that the proposed $50 per MWh penalty is excessive. Both parties stated that the market value of traded renewable energy credits is unknown at this point and contended that penalties that exceed or equal the market value of credits may deter a REP from deciding to enter the market. Enron questioned where the penalties collected will go, and recommended that they be used to offset the program administration costs. Shell agreed with Enron on this point. Enron recommended building upon what other states, such as Massachusetts and New Jersey, have done. Similar to those states, upon the first offense, Enron suggested a public warning be issued and that the commission specify a deadline by which the REP must rectify the deficiency of credits. If the REP does not comply with the commission's order, and depending upon the reason for noncompliance, the commission could suspend the license of the REP or notify the REP's customers of the noncompliance. Enron suggested that the commission may prohibit the REP from accepting or soliciting additional customers if a pattern of noncompliance persists. As a last resort, or in the case of egregious noncompliance, Enron proposed that the commission revoke such REP's license. Shell, Reliant, and CSW agreed in their reply comments with Enron on this type of penalty structure; however, EDF and the Coalition disagreed. Enron further commented that it would be unfavorable to REPs to require them to disclose the average market value of their annual credits in connection with assessing a penalty when the disclosure of the price for credits is not otherwise required.

OPC and Cities commented that if it is significantly more costly to acquire credits on the open market, $50 may not be an appropriate fee because REPs will prefer to pay the fee rather than acquire renewable energy. OPC and Cities further maintained that price disclosure should be required because the assessment of the average market value of credits is likely to be highly inaccurate if price disclosure is not required. OPC and Cities further commented that transaction reports for RECs should include both price and quantity. OPC and Cities contended that the purpose of the REC auction is to balance supply and demand, and to provide a market-based incentive for entry into the renewable resources market. However, if the price of a REC is not disclosed, a potential producer of renewables will have no way of knowing whether a potential for profit exists. OPC and Cities supported the levying of the lesser of two sanctions, such that the $50 per MWh penalty may act as a ceiling thereby preventing the penalty from becoming extremely onerous. TEC submitted that the proposed rule's penalty provisions should recognize the reason for a retail energy seller's failure to meet renewable energy goals and recognize that the retail energy seller can not control the action of the renewable energy supplier. TEC also noted that one element of a competitive market is price disclosure and that prices paid for RECs should be disclosed and made available to market participants on an after-the-fact basis. Several parties referred to penalty provisions contained in the Arizona renewable energy scheme and the Acid Rain program administered by the EPA.

The commission notes that the penalty provisions contained in this section were drafted and discussed in several task-force meetings as one element of a comprehensive program design package. The proposed penalty for non-compliance is the *lesser* of either $50 per MWh or twice the average market value of credits. As many parties agreed, meaningful penalties are a necessary component of a successful trading program; the penalties included in the rule provide a fair and substantial incentive for all competitive retailers to comply with their ongoing REC purchase requirement. Moreover, additional risk-management provisions included in the rule such as six months of early banking, a 5.0% deficit allowance for the program's first two years, and three-year banking allowance for all RECs, provide competitive retailers with the flexibility needed to comply with the requirements set forth in this section. These provisions eliminate the need for any type of graduated penalties suggested by some parties.

The commission disagrees with Shell's suggestion that penalties be completely waived if the state's capacity targets are met in any given year. Shell's proposal would eliminate the incentive for all competitive retailers to comply with the rule and would encourage free ridership and uncertainty in the REC market. The commission also rejects Cities' comment that the penalty provisions in §25.173 do not apply to municipally-owned utilities or distribution cooperatives. PURA §39.002 specifically states that §39.904 applies to municipally-owned utilities or electric cooperatives that offer customer choice. Moreover, §39.002 states that where there is a conflict between the specific provisions of Chapter 39 and other provisions of PURA, the provisions of Chapter 39 control. Section 39.904(c) requires that the commission adopt rules necessary to administer and *enforce* the statute. Under this statutory authority, the commission may enforce the provisions of the proposed rule. Additionally, the commission finds authority to enforce the proposed rule under §39.157(e), which gives the commission jurisdiction to establish a code of conduct that must be observed by municipally-owned utilities or electric cooperatives and their affiliates to protect against anti-competitive practices. Enforcing the provisions of the proposed rule against some competitive retailers and not others would result in competitive advantages for municipally owned utilities or electric cooperatives that offer customer choice. The commission finds that municipally-owned utilities or distribution cooperatives that offer customer choice in the restructured competitive electric power market must be held accountable to the same enforcement standards applied to all other competitive retailers. The commission therefore declines to make any recommended changes to subsection (o) relating to penalties.

Second, the commission asked parties to list the appropriate combination of requirements that would ensure that the electric industry collectively achieves the state's capacity goals in the most economically efficient manner. The commission specifically inquired whether 400 megawatts (MW) of new renewable generating capacity could be installed in Texas by January 1, 2003 if: the credits trading program (1) begins in 2003, (2) allows 5.0% deficit banking for the first two compliance periods, and (3) does not require a new capacity conversion factor to be used until 2006. The commission also sought comment on the appropriate trading program start and end dates.

With respect to an appropriate program start date CSW, Duke Solar and Boeing, EGS, EDF, SRAT, Shell, TIEC, TREIA, and the Coalition stated that the trading program should begin on January 1, 2002. APX, PUB, and OPC stated that the program should begin before January 1, 2003. EDF, Shell, SRAT, and TIEC stated that a January 1, 2002 program start date corresponds with the beginning of competition in Texas. EDF opined that this timeline would ensure that 400 MWs of fully *performing* new renewable resources are in place by January 1, 2003 consistent with §39.904(a) and (c)(2). CSW and TREIA stated that a January 1, 2002 start date would allow renewable generation developers to gradually install renewable facilities during 2002 and could potentially lower the costs to customers if federal legislation extends the renewable energy production tax credit (PTC) through mid-2003.

CSW and the Coalition noted that an extension of the PTC would be limited and require developers to immediately install facilities to insure qualification for the credit. Using a capacity conversion factor of

35%, CSW quantified the potential cost savings to Texans. Assuming that the first 400 MW capacity requirement were installed in time to qualify for the $0.019 tax credit, 1,226,400,000 kWhs could be purchased for $0.019 less than those built without the benefit of the credit, yielding a cost reduction of $23,301,600 in the first year of the program. This annual cost reduction would be reflected in each of the first ten years of service for a project that qualified for the PTC. TXU disputed the savings presented in the CSW example, stating that the start date should not be based on hopes or expectations of congressional action.

Reliant, SPS, TNMP, and TXU stated that the start date for the trading program should be January 1, 2003. Reliant stated that the proposed rule requires contracts representative of new installed renewable capacity to be in place and producing a full year's worth of energy, a requirement not expressed in SB 7. Reliant opined that efforts to enforce penalties against a retail competitor possessing its full allocation of renewable capacity under contract by January 1, 2003 would be legally unsustainable. TXU remained concerned that by using a January 1, 2002 start date, it may not be physically possible to construct the facilities necessary to meet its renewable purchase requirement. TXU submitted a timeline to justify its assertion. Reliant was concerned that transmission constraints in ERCOT might limit the ability of the renewables industry to install 400 MW of capacity in time to meet the target in the draft rule. Reliant stated that a program commencement date of January 1, 2003 would allow transmission providers additional time to upgrade the necessary transmission facilities.

CSW, the Coalition, Shell and TREIA sharply disagreed with TXU's claim that the renewable industry could not install sufficient capacity in time to build 400 MW of new capacity by January 1, 2003. CSW asserted that it is likely that renewable resources will be gradually installed throughout 2002, and the total output supplied by generators will exceed the total energy required for REPs to meet their renewable purchase requirements. CSW also pointed out that TXU's estimated schedule for completion of a renewable project is grossly overstated and maintained that a REP wishing to sign a contract today could receive energy from a 100 MW wind farm within 18 months or less. CSW justified its position based upon its experience adding 75 MW to the Southwest Mesa Wind Energy Project in Upton and Crockett Counties, Texas. This project demonstrated that a substantial wind project could be completed in much less than the 28-42 months suggested by TXU. For example, the turbine order was placed in November 1998 and delivery began in March 1999 at a time that over 800 MW of wind energy was installed in the US. Moreover this 75 MW wind farm was completed and operational within nine months after the commission's approval of the project. CSW also stated that TXU's schedule for completing new renewable facilities ignores the following facts: (1) site identification work is in many cases already done or in process; wind energy sites in Texas have already been leased, optioned or purchased by developers in excess of 400MW, (2) private developers of these wind sites are currently conducting meteorological studies, and (3) environmental studies can be completed in less than three months concurrently with geotechnical and engineering site layout work.

Shell Energy also disagreed with TXU's assertion that the 400 MW target can not be met, mentioning that American National Wind Power (ANWP) is currently developing a 250 MW site in Culberson

County. TREIA disputed TXU's assertion, noting that Texas industry is installing more than 145 MW of new renewable resources during 1999 alone. The Coalition stated that TXU's lengthy project schedule may be due to the fact that TXU's Big Spring wind project experienced a series of delays associated with regulatory intervention and litigation, external litigation involving patents associated with the initial technology chosen for the project, and a change in project ownership. The Coalition submitted a project development schedule that it believed was more typical, indicating that the wind power industry, contingent upon REPs appropriately contracting for new renewable energy, could easily achieve the installation of 400 MW of new generating capacity by the beginning of 2002.

Although TXU stated that it would be challenged to meet its projected 160-MW requirement, the Coalition replied that the construction of a 160-MW project is quite feasible. The Coalition illustrated this point with Enron Wind Corporation's two Storm Lake, Iowa projects, built simultaneously, at the same location, and equaling more than 192 MW. The Coalition also pointed out that TXU does not have to obtain all 160 MW of its projected initial REC requirements from one project; it has the option of contracting for output from multiple projects, possibly developed by separate entities. The Coalition justified the industry's ability to build new capacity, stating that during the twelve-month period from July 1998 through June 1999, approximately 1,000 MW of wind power capacity, worth approximately $1 billion, was installed in the United States. TXU also submitted that the time required for wind turbine delivery alone may be closer to 12 months after the manufacturer's receipt of the order. The Coalition was perplexed as to the source of such information and NEG Micon, a member of the Coalition and one of the world's leading turbine suppliers, reported that it can deliver turbines within 14 to 16 weeks after receiving a "Notice to Proceed". Representatives of Vestas, another world leader in turbine manufacturing and Coalition member, stated that deliveries typically occur six to eight months from the date of an order. Enron Wind currently can deliver its domestically manufactured turbines within six months of an order, and internationally manufactured 1.5 MW turbines within two to three months of an order. With respect to the project development schedule, TXU argued that it was aggressively assuming nine months for engineering, procurement, and construction. The Coalition countered TXU's assumption by pointing out that the construction of FPL Energy's 75 MW wind farm was accomplished at a remote and challenging location in only five months.

As an alternative to a January 1, 2003 program start date Reliant, TEC, and TXU proposed using the actual installed faceplate capacity, as verified by the commission or program administrator, to determine compliance with PURA §39.904(a), rather than the energy production required by the proposed rule. The Coalition disagreed, commenting that it is neither appropriate nor necessary to alter a fundamental element of the trading program for the first two compliance periods. Despite the fact that the capacity conversion factor (CCF) is administratively set at 35% for the first two compliance periods, program efficiencies remain an important objective, and it would be disruptive to switch from a capacity-based to an energy-based credits trading program.

With respect to the appropriate trading program end date, CSW, the Cities, EGS, Reliant, SPS, TIEC, and TNMP stated that the end date for the trading program should be in 2009 because there is no legislative requirement that the trading program extend beyond that date. The Coalition disagreed with this assertion, stating that the directive of PURA §39.904(c) requires the commission to adopt rules necessary to administer and enforce the renewable energy mandate; this language sufficiently supports the commission's initiation of program requirements prior to 2003, any early banking provisions, and continuation of program requirements beyond 2009. The Cities and SPS stated that §39.904 milestones are evaluated on the basis of whether renewable capacity has been installed. The Cities also stated that extending the end date beyond 2009 is inconsistent with preamble language that there will be no economic costs incurred by persons who are required to comply with the new rule beyond those costs caused by the underlying statute that it implements. Extending the compliance period an additional ten years, Cities continued, will significantly increase costs for parties that must purchase renewable energy credits.

EGS and TXU acknowledged the concern that some stakeholders have expressed that in order for RECs to be available for trading through 2008, renewable energy generators must have certainty that a market will exist for their renewable capacity after January 1, 2009. This concern is that investors will be unwilling to fund a renewable project in years 2007 and 2008, and perhaps earlier, unless they can be sure that there will be buyers for this capacity after January 1, 2009. Both EGS and Reliant argued that the commission may not unilaterally decide to continue the program beyond 2009 without a specific mandate in SB 7. CSW, the Cities, EGS and Reliant opined that conformance with the end date of the statutory goals need not hinder the credits trading program if it needs to operate beyond 2009. CSW stated that the Legislature would be in a position to extend the program if necessary.

Austin Energy, Duke Solar and Boeing, EDF, OPC and the Cities, TREIA, and the Renewable Coalition stated that the end date for the trading program should be December 31, 2019. Austin Energy, OPC and the Cities, and TREIA, and the Coalition maintained that the program must have an extended end date to provide a sufficient level of certainty for financing renewable investments. EDF stated that ending the program in 2019 should provide enough time for suppliers to recover the costs of previous investment in renewables as well as those costs associated with the last 600 MW capacity installment required in 2008. If the program is not extended, continued EDF, renewable energy providers may be forced to try and recover these capital costs in only a year or two of sales with extremely high prices containing an additional risk premium.

CSW, Enron, EDF, OPC and Cities, and Shell suggested that under appropriate circumstances, the program could be ended earlier than 2019 using a market-based approach. These parties concurred that the program could essentially end automatically as the cost of renewable energy decreases over time and the price of a renewable energy credit becomes zero dollars. These parties proposed that the commission should determine the program's termination date at a later time based on empirical evidence justifying that a trading program would no longer be necessary to sustain the mandate. Shell added that an uncertain end date might accelerate the installation of new renewable capacity. TREIA countered that an end date of 2019 was better than a market-based approach. TREIA asserted that self-sunsetting actually would increase compliance costs by introducing risk for projects built prior to 2009. If the value of RECs go to zero, TREIA continued, the only advantage that REPs would gain from "self-sunsetting" would be the elimination of administration costs, which are expected to be low.

In response to questions regarding deficit banking, PUB, OPC and Cities, Reliant, TIEC, and TXU, supported the flexibility offered by the prospect of 5.0% deficit banking. OPC and Cities noted that the concept of deficit banking is one part of the compromise created by the task force members to garner support for the strong penalty provisions of this section. Reliant presented a numerical example of deficit banking that showed it could work as a risk management tool while still allowing compliance with the 2003 mandate.

EDF, OPUC and Cities, SPS, TREIA and TIEC were concerned that the 5.0% deficit banking allowance could reduce the commission's ability to ensure that capacity goals are met. SPS supported the position that any shortage banked under the deficit banking provision should be made up in the following year. EDF further stated that deficit banking is not needed as a risk management tool.

With respect to an appropriate CCF, PUB agreed that the commission should use actual capacity factors to calculate the CCF in the future as actual performance of technologies becomes known. Reliant suggested that the CCF be adjusted biannually. TIEC stated that the CCF should be adjusted in 2004, not 2006. TREIA argued that the 35% fixed CCF reduces the commission's ability to ensure capacity goals are met. The Coalition stated that achieving the initial capacity target set by the Legislature depends in large part on whether the initial 35% CCF is accurate and that the end of the program's first year will illustrate whether or not that is the case. The commission should therefore reevaluate the CCF and assess the success of the program during the program's first settlement period in the first quarter of 2003.

SPS stated that wind turbines likely will perform below the proposed 35% capacity factor in its service territory. SPS's most recent project is anticipated to have a 32% capacity factor. SPS argued that it will have to add 10% more turbines to achieve its energy purchase requirements set forth in the proposed rule.

The commission agrees with TIEC, CSW, Duke Solar and Boeing, the Renewable Coalition, Shell, EDF, TREIA, and SRAT, that the REC trading program should begin on January 1, 2002, for several reasons. First, Congress has extended the 1.9 cents per kWh PTC for wind energy. To qualify for this credit, facilities must be producing energy *no later* than December 31, 2001. This credit will significantly reduce the cost of wind energy and will lower program compliance costs for competitive retailers and their customers. A January 1, 2002, program start date should provide an incentive to complete projects before 2002, so as to qualify for the PTC. Second, the commission is not persuaded by TXU's position claiming that developers can not build sufficient resources before January 1, 2002. As CSW, the Coalition, and Shell Energy discussed, prudent buyers and sellers of renewable energy are already making preparations for developing sufficient renewable capacity to meet the first 400 MW target. If wind power is consistently the renewable technology of choice during the next ten years, Reliant's concern about transmission constraints may become a reality. However, this does not appear to be a hindrance to wind energy project development in the immediate future. The commission commits to continue working with the ERCOT ISO and transmission service providers to ensure that transmission constraints are alleviated across the state. This should help mitigate any potential increases in trading program costs associated with transmission congestion. The commission therefore declines to make any of the recommended changes to the program start-date, noting that the provisions as proposed are consistent with PURA §39.904(c), directing the commission to establish a renewable energy credits trading program.

Additionally, the commission declines to amend the program end-date as set forth in subsection (m) of this section and agrees with Austin Energy, EDF, OPC and Cities, Duke Solar and Boeing, TREIA, and the Renewable Coalition that a December 31, 2019, program end date will provide certainty for suppliers financing renewable investments, ensure that all 2,000 MW are installed, and would likely reduce the overall cost of compliance to competitive retailers and their customers. First, the commission notes that the majority of stakeholders were in agreement during the task force meetings that a trading program extending beyond 2009 would decrease compliance costs for competitive retailers and ensure the installation of the final 600 MW of capacity required in PURA §39.904(a). For example, increased certainty for suppliers would likely reduce their financing costs, resulting in reduced overall compliance costs for competitive retailers and their customers. If competitive retailers are not required to hold credits beyond 2009 it is possible that the costs of the last 1,050 MW of required capacity may significantly increase, as suppliers seek to recover the above market costs associated with this capacity over a five or two year period. If the cost of renewable energy or the credits were to increase significantly, competitive retailers might choose to pay the penalty instead of purchasing the energy associated with this high cost capacity, resulting in noncompliance with the statutory requirements set forth in PURA §39.904.

The commission clarifies that a ten-year continuation of the trading program to 2019 does not require competitive retailers to purchase additional capacity beyond the 2,000 MW required in the statute; it merely requires them to hold credits for this period. If the price of credits falls to zero dollars before 2019, the commission, in assessing the program, would end the program if it determines that the trading program is no longer necessary. Second, the commission notes that PURA §39.904(c) requires the commission to adopt rules necessary to administer and enforce the renewable energy mandate. This language gives the commission sufficient latitude for the initiation of program requirements prior to 2003, any early banking provisions, and continuation of program requirements beyond 2009. Moreover, the 5.0% deficit banking provision allowed under subsection (m)(2) will not reduce the commission's ability to ensure that capacity goals are met. All competitive retailers incurring such a deficit must make up the amount of RECs associated with the deficit in the next compliance period. All of these elements of the program set out in the rule contribute to meeting the objective of PURA §39.904, the installation of the specified amounts of renewable resources in a cost-effective manner. The commission therefore determines that the language contained in subsection (m) of this section should not be changed.

Third, the commission sought comment on the metering and verification of renewable energy output as required by this section, asking which parties should be responsible for the metering and verification of renewable energy output data.

Almost all parties agreed that the renewable energy generator should be responsible for metering and verification of energy output data. Only PUB suggested that the program administrator or another independent third party be responsible for metering and verification of energy output data. Reliant, CSW and EDF proposed that renewable energy metering and verification be subject to the same standards as that of any other generator interconnecting to the grid. CSW noted that ERCOT has established generation metering and verification standards in the ERCOT operating guides and suggested that renewable generation should meet and comply with the same standards for interconnection as all other generators in a qualified power region, including metering and verification requirements. TREIA suggested that the program administrator establish such standards.

Boeing and Duke Solar suggested that British thermal unit (BTU) calculations rather than metering could be used to determine the energy saved by generation offset technologies, such as solar water heating. They also suggested allowing the energy produced from renewable sources in hybrid plants to be eligible for credits. OPC and Cities agreed with these changes, TXU objected.

With respect to renewable generators and the reporting of metering and verification data, parties suggested that data be reported to either the ISO or the program administrator. TXU, TNMP, and APX favored reporting directly to the program administrator, while Reliant, TEC, Brazos and Rayburn, and the Renewable Coalition favored reporting to the ISO. OPC and Cities stated that metering and verification information should be shared between the generators, market participants and program administrator.

Many parties proposed that the program administrator would be responsible for the aggregation of the production data and verification of the accuracy of the metered production data. TXU, TREIA, the Coalition, and Shell indicated that this would include making spot checks and audits. Brazos and Rayburn and TEC maintained that the ISO should be responsible for verifying production data as well as generation-offset, off-grid, and on-site distributed renewable resources. According to EDF, the burden of proof remains with the producer, regardless of who does the verification. Enron argued against the existence of a program administrator, proposing that each generator issue its own RECs.

The commission agrees with EDF that the burden of proof remains with the generator. The BTU calculations suggested by Duke Solar and Boeing would be an acceptable method to determine the energy saved by generation offset technologies. However, the commission agrees with other parties that accuracy of metered production data should be verified by the program administrator and amends subsection (g)(9) to reflect this conclusion.

Fourth, the commission sought comment on the banking provisions currently proposed in this section, specifically asking whether the three-year banking provision contained in the proposed section would help ensure that 2,000 MW of new capacity is installed in Texas by 2009. Parties were also asked whether renewable power generators should be allowed to receive credits for energy produced before the first compliance period (early banking) and how the addition of this provision to the proposed section would impact the achievement of the statutory goal.

With respect to a three-year banking limit for RECs, PUB, CSW, Duke Solar and Boeing, Enron, EDF, OPC, SRAT, Shell, SPS, STEC, the Coalition, TIEC, TNMP, and TREIA supported the banking provision. Brazos, Shell, TEC, and TIEC stated that banking will encourage early installation of renewable facilities. EDF stated that the combination of limiting the life of credits to three years and specifying a program end date of 2019 is a good solution and provides operational insurance without jeopardizing the fulfillment of the legislative goal. PUB, the Coalition, Duke Solar, EDF, OPUC, and TREIA stated that the three-year banking limitation will ensure that participants in the credit trading program will build new renewable facilities and not just accumulate credits. These parties argued that unlimited banking might allow competitive retailers to accumulate enough RECs to meet their assigned requirements without having to build the full 2000 MW of capacity by 2009. Brazos Electric, Shell Energy, SPS, TEC, and TNMP noted that the three-year banking provisions will help smooth normal year-to-year variance in output, provide a more stable trading program and facilitate renewable resource planning.

Austin Energy and TXU opposed limits on banking credits. Austin Energy stated that the proposed three-year life of banked RECs arbitrarily restricts banking, a policy that should be encouraged aggressively. TXU commented that a REC represents actual energy production from a renewable resource, and the benefit gained from the production of that energy was actually realized and does not expire; the benefit of renewable energy production is permanent and the REC earned by that energy production should also be permanent.

Duke Solar and Boeing, the Coalition, and TREIA proposed that the commission should articulate the right to alter restrictions on banking at any time in the future it may be deemed necessary to meet the capacity targets. The Coalition recommended that the commission explicitly reserve in the rule the authority to take such action. The Coalition stated that the actions to be taken by the commission in this regard could include limiting the number of credits banked in prior compliance periods that can be used to achieve compliance in the current period, and reducing the effective life of credits to less than three years. CSW, Shell Energy, and TXU disagreed with this position. CSW opined that canceling a banked REC in order to correct a shortfall would in itself lead to shortfalls in renewable resource additions. CSW recommended that the commission adjust the CCF if needed, as recommended in the proposed rule, to reallocate renewable resource purchase requirements to competitive retailers. Shell stated that having the commission retain the discretion to modify banking requirements at any time during the program's existence would introduce significant uncertainty into the trading program.

EDF stated that it would be better to be more conservative in the beginning of the program in determining banking rights and privileges, than to later be in a position requiring the commission to amend those rights if they are found to be harming the legislative goal. SPS stated that too many restrictions imposed on RECs could diminish their value to zero. This limited value greatly reduces the incentive to own excess RECs.

Although early banking is not allowed in the published rule, Austin Energy, CSW, Duke Solar and Boeing, Enron, EGS, the Coalition, SRAT, Shell Energy, STEC, TEC, TREIA, and TXU supported early banking. Duke Solar and Boeing, the Coalition, and TREIA proposed that six months of early banking be allowed for new renewable facilities. The Coalition, STEC, and TXU argued that early banking could provide early liquidity to the REC market. SRAT suggested that early banking should begin as early as 2000 and should be allowed for existing resources. EDF did not oppose early banking *per se*, but found it hard to imagine scenarios that could provide incentives for early construction of new resources and ensure that the interim capacity targets are met. EDF noted that parties favoring unlimited banking, early or otherwise, have failed to provide the mathematical examples the commission requested. Therefore, EDF commented that the three-year limitation on banking should be maintained and no early banking should be allowed. EDF also stated that allowing the banking of credits produced prior to January 1, 2002 could severely affect the goal if qualifying existing post-1995 resources were allowed to be banked. From a policy view, EDF continued, early banking is a tool to encourage early development of resources, and so applying early banking to already existing facilities would be meaningless as an incentive device. EDF noted that a complicating factor associated with early banking is cost recovery. CSW disagreed with EDF and TIEC that early banking would provide some existing eligible resources with an unfair opportunity to double recover their costs, pointing out that the proposed rule clearly excludes any existing renewables from eligibility in the trading program if they are currently receiving cost recovery through base rates or a power cost recovery factor (PCRF).

Austin Energy, CSW, and Shell Energy stated that early banking is an important component of ensuring that the program achieve the initial target of 400 MW of new renewable resources in 2002, creating an incentive to build renewables in advance of the compliance date. Although TREIA stated its concern that early banking serves to lessen the likelihood that capacity targets will be met, it supported the overall package embodied in the proposed rule, and agreed that a modest level of early banking could be tolerated without jeopardizing compliance with capacity goals. Reliant stated that the intent of forward banking is a risk management tool. If the first compliance period is 2003 with a requirement of 400 MW, Reliant continued, early banking should not be necessary.

TIEC opined that early banking does not seem a viable option, because the commission would need to have the registration and certification procedures in place, and the resources would have to meet all eligibility requirements of subsection (e). TIEC also stated that it is likely that the only renewable facilities which could take advantage of early banking would be new resources that would happen to be planned, built, and operated during the short window of September 1, 1999 through December 31, 2001.

The commission notes that the three-year banking provision contained in the proposed section was as part of a comprehensive program design package agreed to by a majority of stakeholders during several of the task force meetings. The majority of parties agreed that this banking provision would provide competitive retailers with additional flexibility in a trading program based on energy produced by intermittent generating capacity. Other parties agreed, that while not ideal, the three-year limitation would help to ensure that competitive retailers contract for new capacity in lieu of holding accumulated credits for the duration of the program. Parties opposed to this provision were afforded the opportunity, both during the workshops and the formal comment period, to raise and provide justification for changes to the three-year banking limitation for credits. The commission finds that parties have not convincingly shown that the three-year banking provision should be either shortened or lengthened in the context of a comprehensive program design package.

With respect to an early banking provision, the commission notes that, during the task force meetings, most parties agreed that an early banking provision would add liquidity to the market by increasing the number of credits that are available at the start of their program. The commission agrees that an early banking provision will enhance the market's liquidity and provide a more functional market at the beginning of the program while maintaining the economic incentives to build new renewable facilities. This will help provide competitive retailers with additional flexibility and important risk management tools needed to comply with the requirements of the trading program, especially in its early stages. The commission clarifies that an early banking provision does not require competitive retailers to buy RECs at an earlier point in time, but rather allows generators to receive RECs for sale in the trading program prior to the program's first compliance period. The commission therefore amends §25.173(m) to reflect this conclusion.

The commission agrees with CSW, EDF, Shell Energy, and TXU that modifying banking requirements at any time during the program's existence would introduce uncertainty and an additional element of risk for competitive retailers forced to comply with the trading program requirements. The commission therefore declines to amend this section to include a provision retaining the right to alter restrictions on banking at any time in the future as it deems necessary to achieve the required capacity targets. The commission points out that adjustments in the capacity conversion factor as set forth in subsection (j) and commission review of the program as set forth in subsection (q), should adequately correct any capacity deficiencies. The commission therefore declines to amend subsection (g)(5) of this section and finds that the language is consistent with PURA §39.904(c) relating to the establishment of a renewable energy credits trading program.

Fifth, the commission inquired whether it would be necessary to build new renewable resources to offset any reduction in capacity resulting from the retirement of any renewable resources in Texas.

Austin Energy, PUB, CSW, EDF, Duke Solar and Boeing, Shell Energy, TEC, TIEC, TNMP, TREIA, Brazos and Rayburn, TXU, and the Renewable Coalition, stated that the goal for new renewable energy in Texas is 2,000 MW by 2009. However, these parties also pointed out that PURA §39.904 also requires a cumulative renewable capacity of 2,880 MW in Texas by 2009. This assumes that 880 MW of renewable capacity currently exists, will continue to operate, and should be replaced by new resources if any are retired. OPC and Cities and Reliant stated that the Legislature intended to have 2,000 MW of new renewables by 2009. The focus should therefore be on installing 2,000 MW of new capacity and not providing a mandate for the maintenance of existing resources. Therefore, the parties concluded, there is no need to build new renewable facilities if any are retired during the life of the program.

PURA §39.904(a) requires an additional 2,000 MW of renewables to be installed in Texas by January 1, 2009. However, this subsection also states cumulative capacity targets for renewables, culminating with 2,880 MW installed in Texas by January 1, 2009. This illustrates the Legislature's assumption that 880 MW of renewables existed in Texas at the time SB 7 was drafted and will continue to be in existence on January 1, 2009. Therefore, if any of the renewable capacity is retired, new renewables to replace that capacity will have to be built. Moreover, if customer demand for renewables exceeds 2,880 MW, market forces could lead competitive retailers to purchase renewable capacity in excess of what is mandated in §39.904(a). Therefore, the commission concludes that the 2,880 MW requirement indicates the minimum amount of renewable capacity that should be installed in Texas by 2009, not the maximum. Changes to the language in subsection (a) are therefore unnecessary. The commission amends subsection (h) of this section to clarify this conclusion.

Sixth, the commission sought comment on the obligation of municipally-owned utilities, distribution cooperatives, and retail electric providers to purchase new renewable resources in the credits trading program if they have existing renewable resources sufficient to cover their renewable energy purchase requirement. Parties were specifically asked whether entities with existing resources should have their obligation to purchase RECs proportionately reduced to reflect the percent of existing renewables they have under contract. The commission also inquired whether it would be necessary to allow existing resources to produce credits for sale in the trading program if those resources are allowed to offset a party's purchase obligation. The commission also asked parties to explain how all of the following conditions could be met: (1) a party's purchase obligation is offset by existing resources, (2) renewable credits associated with those existing resources are excluded from producing credits for sale in the trading program, and (3) the capacity requirements set forth in PURA §39.904 are achieved in a timely, economical, and efficient manner.

Austin Energy, CPS, CSW, EGS, EDF, LCRA, OPC and Cities, Reliant, TEC, TIEC, TPPA, and the Renewable Coalition generally agreed to a compromise approach that would exclude existing renewables from participating in the trading program, but would allow entities participating in retail competition to use existing resources which they own or purchase to satisfy all or part of their renewable obligation. The principles of this compromise are as follows: (1) existing renewable resources as defined in §25.173(c)(5), other than qualifying existing resources as defined in proposed §25.173(c)(10), that are currently owned by or under contract to an entity would count toward its allocated requirement for as long as they remain under contract (including renewal) or are owned by the entity, (2) existing renewables, other than qualifying existing resources as defined in proposed §25.173(c)(10), may not participate in the REC trading program, and (3) regardless of when an entity chooses to opt into competition, there should be a one-time, up front nomination of the existing renewable resources (based on a ten-year average MWh output) that will be used to offset its allocated requirement. LCRA stated that its proposal would allow those who already own or purchase renewable capacity to count such capacity or purchases toward the allocated renewable requirement.

Such a proposal can not produce windfalls, precisely because the contracts for such renewables are already in place and can not arbitrarily be broken. Such resources can not flood the market because they are already dedicated to existing customers. The price of credits will not affect the price of energy already under contract, nor produce benefits to the owners of existing resources, windfall or otherwise.

CPS, OPC, Brazos and Rayburn proposed methodologies that could be used to offset renewable purchase obligations for entities with existing resources. The Coalition recommended that the commission take great care in implementing the offset for existing resources, as different approaches could have dramatically different implications for the achievement of the program's objectives. For example, OPC's proposal would actually result in less than 2000 MW of new renewables being built, as requirements to buy new renewable RECs are reduced for the owners of existing resources, but are not reallocated to other competitive retailers. Additionally, Brazos Electric's proposed approach would give disproportionate value to existing renewables. The initial allocation of REC requirements would be based on the market shares of all participating retailers. Existing renewables would offset REC requirements, for those that own existing renewables. The total REC requirement would then be allocated across the smaller, remaining base of REPs. The ratio of RECs required to total sales on a per-REP basis would be higher in this allocation than in the initial allocation. With no readjustment of the allocation for the exempted owners of existing resources proposed, the result is that existing resources would have a disproportionate value, relative to new resources, in achieving compliance with program requirements. The Coalition agreed with CPS's proposal, stating that it includes two allocation stages, correctly providing that REC responsibilities are relieved for owners of existing resources on the same basis as they are assigned for REPs which own no existing resources. The Coalition stated that the commission must limit this benefit to output that is under contract exclusively for resale to retail customers. Without such a limitation, this output could be sold and resold on a wholesale basis. TXU objected to an "offset" concept that would use a historical average of energy output from the existing resources in determining the amount of "offset", maintaining that actual energy production each year should be used. TXU and CSW also suggested that, to the extent that trading program compliance is based upon energy, the "offset" provided by existing resources be based upon actual energy produced, and not capacity.

TXU opposed any offset provision. CSW agreed, but stated it was willing to accept a compromise comparable to CPS's proposal. TXU stated that it is unfair and discriminatory to allow those entities to offset their obligation using old, low-cost, low-capacity factor facilities, the capital cost of which may have already been recovered through rates, and will also increase the costs that all REPs, including new REPs, will bear as they enter the competitive market in 2002. TXU further stated that such an exemption would allow municipally owned utilities (MOUs) and electric cooperatives to avoid their responsibility to support the legislative goal at the expense of all other retail competitors. Only MOUs and cooperatives with existing resources would be able to take advantage of this exemption because REPs will not be allowed to continue ownership of generation facilities, renewable or otherwise, following the advent of retail competition. Brazos and Rayburn and the Cities preferred that existing resources be included in the trading program, but that a reasonable compromise would be for municipally owned utilities and distribution cooperatives to offset part or all of their REC requirements with existing renewable resources currently under contract. PUB and State Representatives Merritt and Zbranek supported some form of offset of REC requirements for municipally owned utilities and distribution cooperatives purchasing power from existing renewable resources. CSW alternatively suggested using a "cost test" to qualify existing renewable resources for participation in the trading program. The "cost test" would allow existing renewable resources to prove that their costs were above those of other resources for sale in the wholesale market. Any existing renewables meeting these cost criteria would be allowed to participate in the trading program.

STEC commented that the offset, in principle, was a good basis for a negotiated compromise. EDF strongly preferred this type of solution because it maintains the trading program solely for new resources, allowing that market to operate correctly by setting prices that minimize the ultimate cost to Texas citizens. Brazos and Rayburn and ETC stated that for those cooperatives that do offer customer choice, their load ratio share of their generation and transmission (G&T) cooperative's existing renewables should count toward such opt-in cooperative's REC allocation.

Many parties with existing renewable resources explained why these resources should be allowed to participate in the trading program. APX, Brazos and Rayburn, PUB, ETC, GBRA, SRAT, TEC, TNMP, and State Representatives Wohlgemuth and Zbranek commented that the commission should incorporate existing renewables into the credits trading program, as the continued operation of existing renewables is important in increasing the total MW of renewables operating in Texas. APX, Brazos and Rayburn, and TEC stated that the cost of trading RECs from existing resources would be no higher, and perhaps lower, than the cost of the trading program in which only new resources earned trading credits. APX opined that the commission can define the percentage of new RECs and existing RECs each competitive retailer must purchase to comply with the rule and provide the regulatory push desired to encourage the development of new renewable resources.

GBRA explained that many of the large incumbent providers oppose the inclusion of existing resources in the rule because they have a minimum amount of renewable capacity in their existing mix. By increasing the number of potential suppliers in the market to include existing resources along with entities that construct new projects, the market price for credits should in fact decrease, resulting in an overall benefit to the market. ETC and State Representatives Telford and Wohlgemuth also stated that out-of-state renewables should be included in the trading program in order to be fair to the rural ratepayers and constituents in East Texas. EDF responded by stating that the list of the 880 MW of renewables used by the Senate Interim Committee on Electric Utility Restructuring did not include the 128 MW of out-of-state Southwest Power Administration (SWPA) hydropower allocated to cooperatives in East Texas.

CPS, Coalition, Duke Solar, EDF, OPUC, Shell Energy, and TXU stated their opposition to including existing renewables in the credits trading program. They maintained that awarding RECs to existing renewable resources would seriously undermine the market for new renewable-resource credits and would jeopardize the state's ability to achieve the required amounts of new renewable-resource generating capacity in a cost-effective manner. OPC and the Coalition commented that the inclusion of existing renewables in the program will be more costly in the short-run and decrease the margin for competition in the early, formative stages of the market for electricity. Additionally, the Coalition, Reliant, Shell Energy, and TXU stated that if existing renewables received RECs that their owners would receive an undeserved windfall. TXU provided a mathematical example of such a windfall, concluding that the windfall would be substantial. For example, assuming that the cost of credits averages $10 per MWh over the first ten years of the program, and assuming a 20% capacity factor for existing renewable resources, the value of the credits provided to existing facilities would be over $153 million. TXU stated that owners of existing renewable facilities should not receive a windfall of this magnitude.

The Coalition stated that if owners of existing renewable-generation were awarded only one-half the amount of credits awarded to owners of new facilities, this windfall would be merely reduced, not eliminated, again without producing any additional renewable-resource capacity. Likewise, awarding new renewable resources two credits per megawatt-hour would reduce, but not eliminate, the number of existing resources wielding a competitive advantage over new renewables. Shell Energy stated that it has not seen any data or studies to show that an additional credit per MWh constitutes a sufficient investment incentive to overcome the deterrent effect that existing resources' incumbency advantage would create, or that competitive retailers would purchase energy from these new projects, at a higher cost, simply because they would receive more RECs.

TXU stated that requiring new projects to compete with existing resources in the market for renewable energy credits would create a serious market power issue, particularly during the early years of the program, when the amount of existing renewable capacity will significantly exceed that of new capacity. Even by 2005 and 2006, the existing amount of renewable energy capacity (880 MW) will exceed the goal for new capacity (850 MW). By restricting the credit-trading program to new resources, market power concerns will be greatly minimized. Third, the presence in the credits market of significant amounts of lower-cost, existing renewable sources could inhibit the timely contracting for credits from new sources that will be necessary to support the development of those sources. This could occur if the owners of those lower-cost, existing sources withhold their credits from the market, in anticipation of higher credit prices to be set by new renewable generation, and buyers of credits delay their purchases in hopes of securing lower-cost credits from existing sources. TXU stated that this would stifle the goal of having new generation in place according to SB 7.

CPS stated that simple economics dictate that, in a competitive generation market, the sustainability of an existing renewable resource is jeopardized only to the extent that the incremental production costs of the resource are in excess of the market price of electricity. While some parties have presented data indicating that the *total cost* (i.e., embedded and incremental costs) *may* be greater than the market price for some renewable resources, no data has been presented that would indicate that any of the existing base of renewable resources has incremental production costs that exceed the expected market price of electricity. Given these circumstances, the inclusion of existing renewable resources in the REC trading program serves only to: (1) provide a market-based subsidy toward the recovery of embedded costs that are rightfully addressed in the context of stranded costs (i.e., in the case where the total cost of the renewable resource is greater than the market price); or (2) provide windfall profits to the owners of existing renewable resources (i.e., in the case where the total cost of the renewable resource is less than the market price). CPS does not believe that the REC trading program was created to provide stranded cost subsidies or windfall profits; rather, it was created with a sole purpose in mind—to achieve an *additional* 2,000 MW of renewable resources in the State by 2009.

With respect to the competitiveness of existing hydroelectric facilities, Brazos and Rayburn, GBRA, LCRA, and SRAT noted that the cost of production from their existing hydroelectric resources exceeds projected market values. LCRA stated that the resources are expensive to maintain and the ability to release water to generate electricity is limited by water rights. The resultant output, according to LCRA, GBRA, and SRAT, when apportioned over the cost to operate and maintain the facilities, produces a cost of $36-$38 MWh for LCRA to over $70 per MWH for GBRA and SRAT. LCRA stated that these costs make the hydroelectric resources unable to compete against new combined cycle costs or existing generation for which stranded costs have been recovered. EGS and LCRA argued it would have little incentive to maintain their hydro resources under those circumstances. Brazos Electric provided information on several of its existing hydro contracts, stating that low annual capacity factors and age of these facilities result in average costs that are above market. Therefore, the energy associated with these facilities should be used to generate RECs.

Reliant and TXU expressed skepticism about the claims of the river authorities and stated that more detailed information would be needed to persuade them that hydroelectric resources are in need of assistance. In any event, Reliant and TXU stated that municipal and cooperative electric utilities that opt in to customer choice could recover their stranded costs pursuant to the relevant provisions of PURA Chapters 40 and 41, respectively. Shell Energy stated that the commission should ignore threats that some parties will close their facilities if it does not extend further preferences and subsidies to these already subsidized facilities. Most existing resource owners can sell this energy through existing long-term contracts. Shell questioned the notion that LCRA, whose main purpose is to build and maintain dams and which is adding even more generation capacity to meet all its long-term requirements contracts, will shut down its lucrative generating facilities.

Austin Energy, Brazos and Rayburn, CPS, DGG, Entergy, LCRA, TEC, TIEC, and TPPA took the position that the Legislative mandate in PURA §39.904 includes existing resources. As such, the rule must provide a mechanism that allows for the continued operation of these resources because the 880 MW of renewable resources in existence when the Legislature enacted SB 7 is included in the mandates for 2003, 2005, and 2007. The proposed rule acknowledges this mandate by stating that one of its purposes is "to ensure that the cumulative installed renewable capacity in Texas will be at least 2,880 MW by January 1, 2009."

ETC stated that under the proposed rule none of the hydro power currently under long term contract to Tex-La, NTEC, or SRG&T would count in the renewable energy program, and any member distribution cooperative opting in to retail competition would have to purchase additional renewable energy credits ("RECs") to satisfy the renewable allocation assigned by the program administrator. Not only is this result inequitable, it could run afoul of the provisions of the all-requirements contract between each G&T and its member distribution cooperatives, which already provide for the distribution cooperative's full requirements. ETC continued by stating that in practical terms, the cost of having to acquire a completely new renewable energy allocation is estimated to be, over the 11 year period beginning in 2002 and ending in 2012, on average more than $1.5 million per year for the East Texas Cooperatives' distribution cooperatives if they opt in to retail competition.

The Cities stated that the proposed rule does not acknowledge that municipally-owned utilities were making investments in hydroelectric facilities without having to be pushed into doing it by the commission or the Legislature. Therefore, it is only fair that these units, and others like them, be included in the credits trading program.

TXU stressed that existing renewable resource facilities were built for purposes other than to meet the requirements of PURA §39.904. Dams were built mainly for flood control, water storage, or recreation, with low-cost electricity being a side benefit. TXU emphasized that the ability to obtain power from hydroelectric projects was generally limited to only certain types of entities due to federal preference provisions. Thus, ownership of existing renewable resource facilities constitutes roughly three-fourths of the 880 MW of existing renewable capacity and is skewed towards certain types of entities (mainly river authorities, cooperatives, and municipalities). It would therefore be unfair to provide a monetary benefit to these entities when other utilities in the past simply did not have the opportunity to avail themselves of such renewable resource facilities. Shell Energy rejected the fairness argument submitted by entities with existing renewables, questioning whether it is fair that cooperatives and municipal utilities obtained subsidies and preferences for their renewable resources, while IOUs could not. Shell opined that the cooperatives and municipal utilities built these facilities for reasons of their own choosing to suit their own needs. Shell suggested that the commission should only care whether its rule complies with the legislation.

The commission concludes that existing resources should not be allowed to participate in the credits trading program. The purpose of the trading program is to ensure that 2,000 MW of new renewables are installed in Texas in an economically efficient and least cost manner. This purpose is consistent with PURA §39.904(a), which requires 2,000 MW of new renewables to be installed in Texas by 2009 and §39.904(b), which requires the commission to establish a renewable energy credits trading program. Allowing existing resources to participate in the trading program would either increase costs to all competitive retailers required to comply with the requirements of this rule or reduce the value of RECs so that they do not provide adequate incentive for new producers to add new renewables. For example, a trading program that allowed both new and existing resources to participate would require that each competitive retailer buy a proportionate amount of energy from its "share" of a 1,280 MW obligation for the 2003 compliance milestone. Alternatively, a trading program that allowed only new competitive resources to participate would require each competitive retailer to buy a proportionate amount of energy from its "share" of a 400 MW obligation. During the program's first compliance period, including existing renewables in the trading program would increase a competitive retailer's REC allocation by approximately 300%. If the market value of the RECs is based on the cost differential between new renewables and other new resources, a competitive retailer's costs would increase by 300%. This could serve as a barrier to entry for many REPs attempting to do business in a newly restructured electric power market. Alternatively, the availability of RECs from existing resources might create an oversupply of RECs and depress their value. In this case, the value of the RECs would be inadequate to provide producers sufficient incentive to build new renewable capacity.

Additionally, the commission agrees with the statements of some parties questioning the arbitrary nature of the term "qualifying existing resources" defined in the proposed rule and concludes that it would be more equitable not to allow these resources to participate in the trading program.

However, the commission recognizes that cumulative capacity targets also are stated in PURA §39.904(a). The commission applauds all entities in Texas that have realized the benefits of renewables and have taken the initiative to invest in renewables without the requirement of a mandate such as that contained in SB 7. The commission concludes that an "REC offset allowance" would realize the benefits of existing renewables and ensure that the 880 MW of these resources envisioned in §39.904(a) continue to be utilized until January 1, 2009. This offset allowance would allow all entities with existing renewables to use these resources to proportionately offset their renewable energy purchase requirement for new renewables. This offset allowance shall ensure that the cumulative capacity targets required in §39.904(a) are achieved in a manner that does not unnecessarily raise costs of the overall program to Texas customers.

The commission reflects these conclusions by (1) allowing only facilities installed and placed in service on or after September 1, 1999, the effective date of §39.904, to be considered new and eligible to participate in the credits trading program, with the exception of small producers as defined in subsection (c) of this section, and (2) allowing all competitive retailers to receive an offset for existing facilities owned or under contract by the competitive retailer, its affiliates, or its predecessor nominating the resource since September 1, 1999. Allowing an entity that owns existing facilities or takes power under contract from existing facilities to share the related renewable offsets with its affiliates will assure an equitable allocation of the benefits of having obtained those existing resources. For the purposes of this rule only, the commission determines that all of the individual G&T members of ETEC and STEC and the distribution cooperative members of the individual G&Ts, for example, are affiliates of each other. As a consequence of this determination, these members could use their collective existing facilities or renewable power contracts - whether individually or collectively owned - to ratably share the offset created by those resources. The offset approach has broad support among the parties, will ensure that all entities with existing resources receive the same benefit for those investments, and supports the goal of installing 2,000 MW of new capacity in a cost-effective manner. Providing offsets will also make it easier for cooperatives and municipal utilities that have rights to such existing resources to opt in to competition. The commission agrees with the offset methodology proposed by CPS during the formal comment period. This methodology includes two allocation stages, correctly providing that REC allocations are reduced for owners of existing facilities on the same basis as allocations are made for competitive retailers owning no existing renewable resources. The commission therefore amends subsections (c), (h), and (i) to reflect these changes.

Seventh, the commission sought comment on alternative ways to restructure the credits trading program and specifically requested comments on the proposal outlined in Chairman Wood's October 8, 1999 memo filed under this project number. Parties were specifically asked whether existing renewables should be incorporated into the credits trading program and, if so, what impact this would have on (1) the cost or value of RECs over time, (2) the level of financial incentive offered to new renewable resources, and (3) the overall cost of the trading program. Additionally, parties were asked to explain any necessary changes in the REC allocation methodology set forth in subsection (h) of this section and the capacity factor calculation methodology set forth in subsection (i) of this section to accommodate existing and new renewables.

Entergy, GBRA, and TNMP were supportive of Chairman Wood's proposal. Entergy stated that the distinction between existing and new renewable capacity for the purposes of awarding credits should not unreasonably complicate the credits trading program or affect its costs. GBRA stated that the inclusion of all existing renewable resources in the renewable energy credit (REC) trading program, except those for which the costs are (1) recovered from retail customers who do not have customer choice or (2) recovered as eligible stranded costs, is essential to further the legislative goal of 2,880 MW of cumulative renewable capacity by January 1, 2009. In addition, GBRA opined that Chairman

Wood's proposed additional one credit/MWH for projects less than ten years old will create incentives for new projects in the market. ETC viewed the Chairman's proposal as a good faith, positive effort to resolve the pending disputes but proposed that it be amended to provide that a distribution cooperative can opt in whenever it chooses to.

Senator Ratliff, State Representative Telford, Austin Energy, PUB, CPS, CSW, LCRA, Shell Energy, SPS, TPPA, TREIA, the Texas Renewable Power Coalition, and TXU disagreed with Commissioner Wood's proposal. Shell Energy stated that the proposal fails to address the potential renewables market power advantage that those possessing existing resources would obtain if they participated in the program. Awarding an additional credit per MWh for the first ten calendar years, Shell opined, only partially mitigates this concern. Shell Energy questioned the statement in Chairman Wood's memo that the commission should ensure stability in pricing for the REC program, commenting that enforced stable REC pricing could actually prevent reaching the program's goals. SPS stated that preferential treatment in the issuance of more than one credit for each MWH of production also adds to the allocation problem. For example, if more than one credit is issued for some MWHs of generation, then the allocation must be increased so that these additional credits are absorbed and needed by the REPs, or there would be no need to build generation because the excess credits can satisfy the regulatory requirement in energy but not the legislative capacity requirement.

The Coalition argued that awarding new renewables the additional credit for only the first ten years would effectively require them to compete directly with lower-cost existing renewables beginning in their eleventh years and for the remainder of their service lives. As a result, developers of new renewable projects would seek to recover more of their costs during the initial ten-year period, resulting in higher costs to consumers during the first ten years of operation. The Coalition also averred that awarding post-1995 renewable-resource facilities two credits for each unit of output during the first ten years of their operation would create two classes of new renewables for the years after 2005, those ten or fewer years old which receive two credits per megawatt-hour, and those more than ten years old which receive only one. Over time, the relative proportions of these two classes would change; adding complexity to the calculation of the energy production goals needed to achieve the statutory capacity goals. TXU stated that is was unclear how providing a differential number of credits to certain resources will result in the levels of capacity set out in PURA §39.904(a) actually being installed in this state. To the extent double credits are provided, those double credits simply halve the amount of energy production that must be achieved by new facilities.

Austin Energy stated that although the collaborative process did not lead to resolution of every outstanding issue, it is inappropriate to look for an entirely new approach as a substitute at this time. Instead, Austin Energy asserted that the commission should act decisively to resolve the few remaining issues in the renewables rule. Such action will strengthen the collaborative process that has been used extensively and quite successfully to date during the remainder of SB 7 implementation rulemakings. Without explicitly opposing the Chairman's proposal, Reliant and STEC thought the proposal had problems that could cause complications for enacting the renewables mandate. In considering alternative ways to restructure the credits trading program, Reliant Energy urged caution, stating that it is often difficult to predict how changes to one aspect of the program might affect overall results and could have the unintended effect of compromising achievement of overarching program goals. Austin Energy concurred with this opinion, stating that the Chairman's alternative proposal has simply not undergone the rigors of the collaborative process. Austin Energy stated that if the details required for his suggested implementation were fully developed, it would become clear that the alternative is significantly more difficult to implement and operate than is staff's proposal.

Austin Energy, PUB, CPS, DGG, ETC, LCRA, STEC, State Representative Telford, TEC, TPPA, and State Representative Wohlgemuth stated that the commission should not or can not make opting for customer choice by January 1, 2002, a prerequisite for participating in the credit trading program. PUB, the Cities, and STEC stated that such an incentive is discriminatory because it creates a cut off date to participate in the credit-trading program. Austin Energy, TEC, and TPPA stated that the Chairman's apparent attempt to entice cooperatives to opt-in sooner rather than later conflicts with the position taken by the legislature in SB 7. There, the legislature expressly provided individual cooperatives the ability to determine whether and when they will offer customer choice. Rather than legislate provisions penalizing cooperatives for not offering customer choice by a certain date, SB 7 establishes a policy of maximum flexibility for cooperatives. TPPA also explained that its members' systems are actively making preparations for industry restructuring, and will consider participating in new retail markets authorized by SB 7. However, most are taking a cautious approach, and the local decision to "opt-in" will not be made until local authorities judge that new markets offer clear benefits to their consumers and communities. Brazos and Rayburn, ETC, STEC, and TEC stated that not all, and perhaps few, municipal utilities and G&T cooperatives will opt-in by the first day of retail competition (January 1, 2002). LCRA presumed that it would be subject to the same standard as the G&T cooperatives, and, as a result, none of its 44 wholesale customers could count LCRA's existing renewables if but one of the 44 declines to opt in. CPS opined that the renewable energy goal and the REC trading program have nothing to do with retail competition, as the same type of program could have been implemented in the context of a mandatory purchase requirement on integrated, regulated utilities. Rather, the goal and the program are about creating a public good through a market-based program in an effort to promote least-cost solutions. CPS and TPPA stated that the rationale for the proposed linkage to retail competition is unclear and unwarranted, especially as applied to new resources.

If existing resources were somehow included in the REC trading program, TXU Electric would support the concept that before any of a G&T cooperative's renewable resources could participate, all of that G&T cooperative's distribution cooperatives would have to opt in to retail choice. The decision on whether to opt in to retail choice and participate in the REC trading program would have to be known some time well in advance of the REC program start date, so that all of the other REPs would know the overall impact of the inclusion of existing resources in the REC trading program. Otherwise, REPs will not have sufficient time in which to know what their likely REC requirement would be, and to make plans to meet that requirement.

Austin Energy, CPS, STEC, and TPPA were concerned that the proposal is intended to indefinitely exclude any new renewable resource from the REC trading program for entities that have not opted-in to retail competition by January 1, 2002. As a general matter, CPS submitted that any new renewable resource located in the State of Texas will certainly contribute toward the 2,000 MW goal of PURA §39.904(a), regardless of the opt-in or out status of a particular entity. Therefore, all new resources should be included in the wholesale REC trading program that was created by the Legislature to achieve that goal.

Shell Energy did not support Chairman Wood's proposal, but expressed the view that if the commission decides to move in that direction, it should not accept the cooperatives' and municipal utilities' complaints about tying this provision to their entering competition on January 1, 2002. These entities never cite any statutory provision that would preclude the commission from doing so. At best, some of those parties simply cite a supposed legislative intent they derive from the Act's overall framework. None, however, cite any provision prohibiting the commission from confining the program to those parties that enter competition by a certain date. Requiring those entities to enter competition at the outset to utilize their existing resources does not constitute any manipulation or usurpation of their statutory rights.

As noted in response to comments received on preamble question six, the commission concludes that existing resources will not be allowed to produce RECs for sale in the trading program and that the offset methodology suggested by CPS is a more cost-effective approach to equitably implement PURA

§39.904. The applicability of this offset provision for distribution cooperatives and municipally-owned utilities *does not* require all of a G&T's distribution cooperatives to offer retail choice by 2002, a concept proposed by Chairman Wood and opposed by many parties.

Comments on proposed subsections

Several parties provided additional comments on various subsections of the proposed rule. Comments not previously summarized and addressed as part of responses to questions posed in the preamble are discussed below.

Comments on §25.173(a)

OPC and Cities opposed the language in this subsection ensuring that the cumulative installed capacity in Texas will be at least 2,880 MW by January 1, 2009. OPC and Cities argued that the legislative goal is met when 2,000 MW of new renewable energy is installed in Texas. These parties proposed that this language either be deleted, or at a minimum, the words "at least" be removed.

As noted in response to preamble question number five, the commission does not find it reasonable to change this language. Subsection (a) expresses the statutory goal that a cumulative renewable capacity of at least 2,880 MW be installed in Texas by January 1, 2009.

Comments on §25.173 (b)

EPE suggested that an additional sentence should be added to the applicability subsection of the rule, which states that this section shall not apply to an electric utility not subject to PURA §39.102(c).

The commission concludes that EPE is not subject to the provisions set forth in these sections until the expiration of the utility's rate freeze period and amends subsection (b) to reflect this conclusion.

Comments on§25.173 (c)

GBRA and Cities commented that the definition of "small producer" under subsection(c)(18) of the proposed rule should be increased from two megawatts to five megawatts to ensure the viability of small hydroelectric units and to be consistent with the federal law definition. The Coalition opposed GBRA's proposal, stating that the two MW threshold resulted from a unique situation, and is designed to assist one 1.8-MW hydroelectric facility that is privately owned.

The commission declines to amend the definition of small producer and clarifies that this definition applies to all renewable energy facilities, not just hydropower. The offset methodology added in subsection (h) of this section will benefit existing hydropower facilities larger than two MW.

TXU proposed changing the definition of "renewable energy technology" to include those technologies that use a *de minimus* burning of fossil fuels. CSW agreed with TXU on this recommendation.

The commission declines to amend the definition of renewable energy technology in this section, as it is consistent with the definition set forth in PURA §39.904(d).

Shell suggested modifying the definition of "renewable energy credit" (REC) and "new resources" because the definitions as written are impermissible under the Commerce Clause.

The commission concludes that there is a risk that parties may challenge this rule on the grounds that it is impermissible under the Commerce Clause. The commission amends the definition of renewable energy credit in this section to reduce the likelihood of such a challenge. The commission concludes that all RECs, whether generated in Texas or elsewhere, must be physically metered in Texas and verifiable by the program administrator. In order to verify the output from a renewable source, the generator must demonstrate that the renewable energy actually reaches Texas. The intent of this requirement is to ensure that all RECs participating in the trading program represent actual megawatt-hours of renewable energy for consumption by Texas retail customers. Renewable facilities that deliver electricity into a transmission system where it is commingled with electricity from non-renewable resources could not be verified as delivered to Texas customers. In addition, the commission emphasizes that 2,000 MW of new renewable capacity shall be installed in Texas by January 1, 2009. Therefore, any capacity shortfalls that arise during the course of the program shall be made up in the REC allocation requirements for competitive retailers. The commission amends subsection (h) of this section to reflect this conclusion.

Comments on §25.173 (d)

Shell Energy stated that the rule should require municipal utilities or cooperatives to bear a proportionate share of RECs upon opting in to competition during a compliance period.

The commission agrees with Shell and points out that this requirement is set out in subsection (d)(1) of this section. Therefore, no amendment is necessary.

Shell recommended that renewable generators alone pay program costs. The Coalition disagreed, stating that generators will interface with the program through the certification process, and it is perhaps appropriate that the costs associated with that process be paid by the generators. There may be other certification processes, the cost of which can be borne by the party seeking certification. In addition, costs associated with a specific transaction, such as REC transactions, can be assigned to the transacting parties. However, RECs are the core of the program, and the Coalition stated that it is most appropriate to allocate general program costs, as well as costs associated with allocating REC requirements and monitoring compliance, among REPs on the basis of market share.

The commission declines to apportion program cost responsibility among market participants in this section. The commission notes that this issue was never addressed in any of the technical "task force" meetings and should therefore be resolved under a separate proceeding related to the program administration function.

Comments on §25.173 (e)

CPS noted, that while the rule as proposed does not necessarily prohibit the output from facilities meeting the requirements of PURA §39.904(f) from receiving renewable energy credits (RECs), §25.173(e) should be amended to specifically include such facilities.

The commission agrees with CPS and amends subsection (e) to clarify that facilities meeting the requirements of PURA §39.904(f) are eligible for participation in the trading program.

Duke Solar and Boeing Company strongly recommended modification of subsection (e) to ensure that the full range of industry-standard solar thermal technologies will be eligible to compete in the Texas renewable energy market. For a new renewable energy technology that operates principally on a non-combustible renewable resource, such as solar thermal or geothermal energy, and uses fossil fuel as a back-up or secondary fuel, credits may be earned only on the renewable portion of energy production.

The commission agrees with Duke Solar and Boeing Company's suggested language and amends subsection (e) to reflect that RECs produced by these types of facilities would be earned only on the renewable portion of energy production. The commission additionally amends subsection (e) to clarify that the capacity contribution toward meeting the capacity goals must be adjusted to reflect the percentage of energy that is produced by the secondary or back-up fuel.

Shell Energy noted that, while subsection (e)(2) prevents a resource's above-market costs from being included in the rates of any utility, municipally-owned utility, or distribution cooperative, the rule does not specify how to determine whether a resource's above-market costs were included in a utility's rates; nor does it define "above-market costs." Shell recommended amending the rule to provide that above-market costs include that portion of costs associated with a renewable energy resource that the owner can not reasonably recover from customers in a competitive retail or wholesale market. CSW proposed that "above-market costs" should be determined by comparing the costs of renewables with the costs of traditional fossil fuel resources.

The commission declines to accept Shell's proposed definition for the words "above-market costs." The commission concludes that the term "above-market costs" when referring to costs associated with new renewable energy facilities, is self-explanatory; they are the difference between the cost of these facilities and the cost of any other type of new generating facility. The commission declines to incorporate Shell's suggested definition into this section, as it is unnecessary.

The Coalition endorsed the requirement set forth in subsection (e)(2), and added that all resources owned or under contract with municipal utilities and distribution cooperatives should also be subject to this provision. The coalition explained that municipally owned utilities and distribution cooperatives not offering customer choice will not be subject to the same competitive discipline as REPs. Nor will they be subject to the type of rate review traditionally applied by the commission to fully regulated electric utilities. As a result, they may be able to allocate some of the above-market costs of their renewable-resource-based power to their captive retail customers, while reducing the prices of their renewable energy credits and thereby undercutting competing suppliers in the credits market. This would depress prices in the credits market and, in turn, dilute the incentive for competing developers to construct the new renewable generating facilities envisioned by the Legislature.

The commission agrees with the Coalition and points out that this requirement is already set out in subsection (e)(2) of this section. Therefore, no amendment is necessary.

The Coalition also recommended establishing a date certain to serve as a cutoff date for capacity additions at existing renewable-resource generating facilities allowed under subsection (e)(3). Capacity additions made prior to this date would not be eligible for the credits trading program.

The commission agrees with the Coalition that incremental capacity additions made prior to September 1, 1999 should not be allowed to participate in the trading program. The purpose of the trading program is to allocate the above-market costs associated with new renewable capacity in a least cost manner. The commission amends (c)(7) to reflect this conclusion.

TXU pointed out a slight inconsistency between two provisions concerning repowered facilities. Subsection (e) provides that only a qualifying existing resource, a new resource, or a small power producer is eligible to earn credits. TXU noted that a repowered facility does not fall within one of these categories. This is inconsistent with subsection (e)(3) allowing the energy produced by the incremental capacity from the repowering of existing renewable facilities to earn RECs. If the intent is to allow the energy associated with the incremental capacity obtained by repowering facilities to earn RECs, then §25.173(e) should be modified. CSW agreed with this change but added that the provision should be further revised to clarify that expansions of existing resources are also eligible to produce RECs in the trading program.

The commission agrees with TXU and CSW and amends subsection (c)(7) to include incremental capacity and its associated energy in the definition of a new resource. New resources are eligible to produce RECs in the trading program; additional changes to subsection (e) are therefore not necessary.

Comments on §25.173(f)

OPC and Cities opposed the exclusion of renewable energy capacity additions associated with an emissions reductions project under Health and Safety Code §382.01593, stating that PURA does not require an exclusion of such capacity additions. In fact, the prohibition preventing renewable energy capacity from qualifying for both programs is likely to reduce or even eliminate the possibility that renewable resources would be built to meet the requirements of the Health and Safety Code. Instead, the commission should use every opportunity to encourage utilities to reduce emissions and improve air quality through the installation of new renewable energy technology. EDF contended that the clean air provisions of SB 7 including this renewable energy program were contemplated separate from the renewable energy option in Senate Bill 766 (SB 766), Act of May 30, 1999, 76th Legislature, Regular session, chapter 406, 1999 Texas Session Law Service 2626, 2628 (Vernon) (to be codified as an amendment to Health and Safety Code §382.05193) relating to emissions reductions projects. Double-counting a "grandfathered" facility's requirements under Health and Safety Code §382.05193 and PURA §39.904 does just the opposite, it would diminish the clean air benefits contained in SB 7 and SB 766. CSW disagreed with EDF's position. The Coalition agreed with EDF, reporting that it has submitted comments in a rulemaking proceeding of the Texas Natural Resources Conservation Commission (TNRCC) regarding modifications to its rules implementing SB 766. In those comments, the Coalition supported a corresponding prohibition on units of output from renewable-resource facilities being simultaneously eligible for both (1) the credits trading program established to implement the renewables mandate of SB 7 and (2) the TNRCC's emission reduction credit program established under SB 766.

The commission agrees with EDF and the Coalition that the provisions contained in SB 7 and SB 766 are two separate programs relating to the policy of cleaner air for Texas citizens. Allowing a company to satisfy two requirements by complying with a single project would reduce the overall deployment of these resources and associated goal of cleaner air. The commission also points out that the language contained in subsection (f)(1) is consistent with language contained in the rulemaking currently underway at the TNRCC. No amendment to this subsection is therefore necessary.

OPC and Cities, TXU, and CSW opposed the prohibition against counting capacity generated by an existing fossil plant re-powered to use renewable fuel, stating that a former fossil fuel plant that is converted to burn renewable fuel is essentially new generating capacity from renewable energy technologies and should count toward the goal in PURA §39.904. These parties contended that such conversions may be among the most cost-effective way to achieve the goal because the avoided capital expenses could be substantial. Furthermore, such a site already has access to the transmission and distribution network and may even possess all the required permitting. EDF argued that the point of the legislation is to provide for new capital investment. Opportunities such as fossil repowering and its close cousin, co-firing, allow arbitrage opportunists to make minimal capital investments to earn credits that do nothing to increase economic development in Texas by providing jobs, producing new equipment for use in Texas, or providing the deployment levels that cause renewable energy costs to go down. The Coalition agreed with EDF, stating that allowing bio-fuels to replace fossil fuel in existing generators to be eligible for RECs would displace and preclude the development of new renewable capacity and violate SB 7's mandate for the development of 2000 megawatts of new renewable capacity

The commission agrees with EDF and the Coalition that one purpose of the trading program is to provide an incentive for new capital investment in cleaner energy technologies. The commission points out that all existing renewable facilities are not eligible to participate in the trading program. One reason for this is that existing facilities have enjoyed cost recovery. This is true for existing fossil fuel facilities; they too have enjoyed cost recovery over the years. The commission also notes that during the task force meetings, not one party was able to adequately explain the process by which an existing fossil fuel facility is repowered to become a renewable facility or the capital costs associated with this repowering concept. Without this type of cost data, it would be difficult to concur with OPC and Cities that allowing repowered fossil fuel facilities participation in the program would be a more cost effective way to fulfill the 2,000 MW requirement. The commission declines to amend subsection (f)(2) allowing these types of facilities to participate in the trading program.

Comments on §25.173 (g)

Shell Energy proposed that this subsection should specify the program administrator's funding source, independence, selection process, and whether the parties under its jurisdiction may appeal decisions to the commission. Shell also recommended a requirement that the program administrator undergo an independent audit every two years, both of its own expenses and of all REC accounts. CSW agreed with Shell Energy's proposals with respect to program independence, audits and appeals changes but does not agree with the selection process changes. This type of selection process takes too much time. The majority of the parties have already expressed that the ISO is well suited to take on this responsibility. The Coalition commended Shell for offering a number of useful recommendations with respect to the Program Administrator's status and responsibilities. These included audits of generators and the Program Administrator, appeal procedures for program administrator actions, and the necessity to keep the Program Administrator independent of program participants. The Coalition and CSW agreed with Shell that REC account status information be kept confidential. This is consistent with the Coalition's recommendation that REC transactions, including prices, should not be recorded. Shell recommended that the Program Administrator provide regular information on total statewide retail sales, in order that REPs be able to predict their market share, and thus their REC requirements. The Coalition, CSW, Reliant, and TXU agreed that such information will be very useful to program participants, particularly retail providers. The Coalition added that performance information of renewable energy systems and technologies, both those installed and participating in the program and those anticipated projects would be valuable information for competitive retailers. The Coalition recommended that the program administrator assess penalties to competitive retailers for non-compliance. TXU disagreed with this concept, stating that the authority to assess penalties lies with the commission. CSW recommended that competitive retailers not in compliance with the trading program should not be reported to the commission as required pursuant to this subsection.

The commission commends Shell for providing useful suggestions that will help ensure effective operation of the trading program, which will benefit all market participants. The commission amends subsection (g) to incorporate Shell's suggested language pertaining to appeals, audits, confidentiality, and program administrator functions. However, as noted previously, cost responsibility and the program administrator selection process will be addressed under a separate proceeding. The commission agrees with TXU that the commission, not the program administrator, should assess the penalties. This is consistent with the language set forth in subsection (o) of this section. The commission declines to accept CSW's proposed change that would eliminate the reporting of non-compliant competitive retailers to the commission. The commission concludes that this type of information is necessary and will assist the commission in enforcing this section.

Comments on §25.173 (h)

Enron suggested language clarifying that providers of last resort would be subject to the requirements of this section. CSW disagreed with Enron's proposed revision, stating that it is unnecessary because the term "retail electric provider" is already defined to include the provider of last resort.

The commission agrees with CSW that this change is unnecessary; PURA §31.002(17) defines a retail electric provider as a person that sells electric energy to retail customers in Texas. A provider of last resort is therefore by definition a REP; no amendment to this subsection is necessary.

Comments on §25.173 (i)

Shell proposed that the rule should require the program administrator to use generation data that the generation facility reports to NERC's Generation Availability Data System ("GADS") program in evaluating the "actual generator performance data." Almost all generators report their performance to NERC, which compiles the Generation Availability Report ("GAR"), used by utilities, regulators and others for a variety of purposes. In general, the Coalition supported the methodology for calculating the capacity conversion factor set forth in the Rule. The Coalition supported the use of actual performance data as the basis of the CCF, although it is important for the commission also to reserve for itself, as it appears to have done implicitly in subsection (i)(2)(D), the authority to make adjustments as necessary to achieve the statutory goals. As the profile of new renewable-resource generating projects participating in the credits program changes over time, performance of new projects may vary from the historical performance of operating projects. Thus, it may not be possible to precisely project the performance characteristics of the next block of capacity using only the historical data of operating projects. Some judgment may be called for to make this projection more accurately, so as to enhance the likelihood of achieving the targeted amount of capacity.

The Coalition also recommended the use of whole-year periods of actual performance data as the basis for recalculating the CCF. This is particularly important when the generating facilities are wind-powered. While inter-annual variation in the wind and solar resources is modest, seasonal or intra-annual variations can be significant. Thus it is critical to include four consecutive seasons (one full year) in sampling periods. For this reason, it may not be practical to recalculate the CCF in the fourth quarter of 2003, as set forth in subsection (i)(2). The Coalition preferred a readjustment in the first quarter of 2003, even though it would be based on only one year of performance. Twelve months' performance data is acceptable as a minimum basis for this calculation, as indicated in subsection (i)(2)(A). And doing so at that point would give REPs an additional three-quarters in which to adjust their contractual arrangements, as needed, before the compliance period begins.

TXU strongly disagreed with the Coalition's suggestion that the CCF be readjusted after the program's first compliance period. TXU maintained that only one year of data will not provide a reasonable approximation of likely average capacity factors. Forced outages, unusual weather, and transmission constraints may all impact energy production in 2002. At least two years, if not three years, is much more likely to produce a reasonable figure. TXU commented that the initial CCF of 35% is too high, but provides a necessary degree of certainty and should apply for three years, not two. TXU agreed in principle with the Coalition that the CCF should be recalculated during the first quarter of a compliance period, not the fourth. CSW opposed TXU's proposed changes, maintaining that the language proposed in this subsection should remain as written. CSW explained that there will be at least four years of data that could be applied towards the CCF calculation if the 1999 wind projects, totaling approximately 150 MW, are included in the data set. Waiting three years could result in missing the legislative targets on either the high or low side.

The commission notes that an accurate CCF is fundamental to successful implementation of PURA §39.904. An accurate CCF helps to ensure that the capacity targets are achieved in a timely and efficient manner. An administratively set CCF of 35% for the first two compliance periods, followed by biennial readjustments based on actual facility performance data, will ensure that the capacity targets are met in an efficient manner. The commission notes that this issue was painstakingly discussed and negotiated in the "task-force" meetings as part of a comprehensive program design package. The commission therefore declines to accept the changes to this subsection as requested by TXU, Shell, or the Renewable Coalition.

Comments on §25.173 (j)

Shell Energy recommended that this subsection should more clearly state that competitive retailers and others may trade RECs. Uncertainty may hamper trading activities and defeat the proposed rule's and the statute's goals. Shell also recommended that the trading program should ensure anonymity in the trading process. For example, the EPA has delegated the SO_2 allowance auction responsibility to the Chicago Board of Trade, which conducts annual auctions of both allowances that EPA has held in reserve and those that private parties have offered for sale. Such a system could allow competitive retailers to trade RECs without fear that entities will gain a market power advantage in trading. Shell also maintained that the rule also should expressly permit several commercially recognized types of transactions. First, it should expressly allow parties to enter into long-term contracts to sell their surplus RECs. Second, it should allow a futures market, where entities agree to sell RECs in given forward periods. The EPA's Acid Rain Rules permit trades in future allowances. Finally, the commission should expand the trading program to allow entities other than competitive retailers, such as brokers, to trade RECs. This latter provision addresses the fear some parties have expressed that an entity might corner the market on RECs. The more entities that can trade RECs, the less likely that any one entity can "corner the market."

The Coalition agreed with Shell that the rule should explicitly make allowance in the REC trading program for a multiplicity of types of transactions and market participants. The Coalition disagreed with

Shell's proposal that the commission should establish a trading/auction system. The Coalition recommended commission intervention only in the event that effective market mechanisms fail to develop of their own accord. TXU did not agree that any of Shell's proposals were necessary.

The commission declines to incorporate Shell's suggestion, noting that such types of transactions are not prohibited under this section. The transactions listed by Shell would be permissible in this trading program.

Shell proposed that the rule should provide for "rounding", stating that a generator producing 0.5 MWh or greater as its last unit generated should be awarded one REC. Doing so will recognize and reward production at the margins, and will especially benefit small producers. TXU agreed with Shell, clarifying that this was the intent of the parties during the workshops, and including an explicit rounding provision in the rule would be appropriate.

The commission agrees with this change, noting that this was the intent of the parties during the task-force meetings. The commission amends subsection (k)(1) to reflect this conclusion.

Comments on §25.173(m)

Shell proposed that the word "periodic" be eliminated from this subsection because one might interpret the word as limiting the times the commission may inspect a facility. Shell also recommended additional language that would clarify that, in the event that decertification occurs, RECs awarded prior to decertification remain valid. The Coalition, CSW and TXU agreed with this change.

The commission agrees with Shell and amends subsection (m) to reflect this conclusion.

Comments on proposed forms

The Coalition and CPS proposed minor modifications to the form to accommodate multiple unit wind facilities and landfill gas facilities. These changes were incorporated into the certification form.

General Comments

The commission received comments regarding the effect of the rule on interstate commerce. ETC argued that the limitation to renewables installed in Texas is a violation of the Commerce Clause, in Article 1, Section 8 of the United States Constitution. ETC contended that the proposed rule's exclusion of out-of-state renewables from the credit trading program or from the required allocation imposed on each REP, MOU, and electric cooperative violates the Commerce Clause, because it treats in-state economic interests more favorably than their out-of-state counterparts. ETC argued that the proposed rule creates a clear, unmistakable preference for in-state renewable resources solely on the basis of their physical location, without regard for the fact that renewable generation sold in Texas by Texas companies for use by Texas consumers furthers the goal of cleaner air in Texas regardless of its origin. ETC maintained that, if the ultimate purpose of the renewables mandate is to provide for cleaner air in Texas, as opposed to creating a market, then the proposed rule should recognize all renewable resources that result in energy sold in Texas, regardless of their origin.

STEC agreed with ETC that the exclusion of out-of-state renewables in the trading program is unconstitutional because it places an impermissible burden on interstate commerce; however, OPC and Cities disagreed with ETC, stating that the proposed rule accurately reflects the intent of PURA §39.904.

Shell commented that the REC definition, which requires a retailer to purchase renewable energy generated in Texas, violates Constitutional prohibitions against a state discriminating against out-of-state commerce. Shell argued that the Commerce Clause prohibits states from engaging in economic protectionism against other states, and that state statutes discriminating against out-of-state commerce are constitutional only if justified by a valid factor unrelated to economic protectionism. Shell asserted that the proposed rule discriminates against out-of-state commerce by requiring competitive retailers to purchase a portion of their energy supplies from Texas sources. Shell interpreted the statute as not requiring competitive retailers to purchase their renewable energy requirement from Texas sources. Shell recommended that the commission allow a retailer to meet its renewable energy requirement by purchasing either Texas or out-of-state renewable energy, while applying the same performance standards to out-of-state suppliers under subsection (e). Shell further noted that line losses and transmission constraints will lead most potential suppliers to locate in Texas anyway, therefore a modified rule will lead to more renewable energy capacity in Texas without violating the Constitution.

The Renewable Coalition disagreed with ETC and Shell, contending that state statutes distinguishing between in-state and out-of-state interests are constitutional if justified by a valid factor unrelated to economic protectionism. In the case of the renewable energy mandate, the legitimate local purpose of §39.904 is the Legislature's desire to capture and develop, rather than neglect and lose, the environmental benefits gained from using Texas' vast, untapped store of renewable resources. This legitimate public purpose can not be furthered without "installing in Texas" the renewable facilities at those sites in Texas where the resources are located; it was not the Legislature's intent to be protectionist.

The Coalition also stated that any person in the country is free to participate in the development of these renewable capacity additions. The Coalition commented that allowing renewable resources from outside of Texas to qualify would totally disconnect the implementation of the statute and rule from the legitimate objectives of the program as conceived by the Legislature. EDF generally concurred with the statements made by the Coalition.

The proposed rule as published is permissible under the commerce clause. The object of the proposed rule was the entirely legitimate goal of improving the air quality for Texas citizens, and the rule was crafted to achieve this goal through efficient and economical development of local renewable resources for the local generation of clean energy. The commission has modified the rule, however, by removing the exclusion of out-of-state renewable resources. The purpose of this modification is to reduce the risk that implementation of this statutory program would be delayed by a commerce-clause challenge to the rule. Beyond the clean-air benefits, the rule provides incentives for the development of an abundant natural resource. The commission finds that the means for achieving these goals are reasonable and do not unfairly discriminate against other states through economic favoritism.

The federal Clean Air Act is implemented through state plans that focus on emissions in local areas. Texas has several areas that are not in compliance with the Clean Air Act standards, including Dallas-Fort Worth, Houston, Corpus Christi, and Beaumont-Port Arthur, and areas that are nearing non-attainment, such as Austin and San Antonio. To help meet the Clean Air Act standards, specific provisions of Senate Bill 7 require the clean-up of plants with high emissions, and the use of clean-burning fossil fuels, such as natural gas, and the use of renewable resources. Cleaning the air in Texas, however, has significant associated costs, and the state agency responsible for preparing implementation plans is in the process of developing a laundry list of air clean-up measures that will affect a number of industries.

New renewable resources, although potentially more expensive than other electric resources, are an effective means for cleaning the air. Through PURA §39.904, the legislature clearly sought to support the development of renewable resources in Texas to efficiently and economically reduce emissions from electricity generation. The demand for electricity in Texas has been and is projected to continue to increase, and the legislature mandated the use of energy derived from renewable resources in Texas so that a portion of the additional future energy generated and consumed by Texans would result in cleaner air for all Texans.

The commission acknowledges the local economic benefits that incidentally result from the rule and concludes that it is permissible for the state, under its sovereign powers, to use markets and market forces to achieve environmental benefits for its citizens. The rule is not a measure for economic protectionism, but, rather, a legitimate program that is consistent with state and federal goals under the Clean Air Act, and is consistent with the mechanism (state action) that is at the heart of the Clean Air Act.

While the commission believes that the rule, as originally proposed, was consistent with the Commerce Clause, it is modifying the rule to reduce the risk of a constitutional challenge. Renewable facilities would qualify for RECs if the output of the renewable facility reaches Texas, so that it can be physically metered and verified in Texas. It is anticipated and intended that the rule will encourage the development of renewable resources within Texas. Renewable resources are distinctly different from coal or natural gas. The wind and solar energy not captured and used today vanishes and can not be recovered. In addition, they are distinctly different in their ability to be transported. Coal and gas can be transported to a suitable location for conversion to electricity, but most renewable resources must be exploited where they are found. Texas has a vast untapped array of renewable resources available for the clean generation of energy. Using these resources will improve the air quality, yet their environmental benefits are wasted unless they are exploited. Clean generation of electricity outside of

Texas also may provide environmental benefits if it is located close to Texas and serves Texas consumers, but it is difficult to draw a line between a location that would and would not benefit Texas air. The rule therefore, allows credits to be accorded to all new facilities located out of the state as long as the energy produced by those facilities meets the eligibility requirements of the rule and is physically metered and verified in Texas.

Any local economic benefits that may result from the state's development of new renewable capacity are incidental to the legitimate goal of providing cleaner air for Texans and developing Texas renewable resources. To foster the development of renewable generation plants in Texas, it is necessary to create incentives. PURA §39.904(c)(2)(B) specifically requires the commission to encourage development, construction, and operation of new renewable energy projects in this state to bring the environmental benefits of clean air to Texas. The rule accomplishes this objective without impeding the flow of interstate commerce.

EDF pointed out that the provisions in this section are interrelated, noting that each commission decision on individual provisions can tend to either promote development of renewable capacity slightly earlier, or to retard development of resources to meet the interim legislative goals. EDF added that decisions were already made in the legislative process to accommodate risk and cost issues raised by utilities. These accommodations have had the effect of delaying and back-loading the acquisition of new renewables relative to a simple and consistent proposal that would have developed 200 MWs of new renewable energy each year for ten years. EDF provided a table illustrating that the graduated increase of new renewables as required in PURA §39.904(a) provided 50% less reduction when compared with a simple program that would have required 200 MW of new renewable energy each year for ten years.

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

This new section is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction, and specifically, Senate Bill 7, Act of May 21, 1999, 76th Legislature, Regular Session, chapter 405, 1999 Texas Session Law Service, 2543, 2558 (Vernon) (to be codified as an amendment to the Public Utility Regulatory Act, Texas Utilities Code Annotated §39.101(b)(3) and §39.904) which entitles all customers access to providers of renewable energy, requires an additional 2,000 MW of renewable generating capacity to be installed in Texas by 2009, directs the commission to establish a renewable energy credits trading program and to adopt rules necessary to enforce and administer the program outlined in this section.

Cross Reference to Statutes: Public Utility Regulatory Act §§11.002(a), 14.001, 14.002, 39.101(b)(3), and 39.904.

§25.173. Goal for Renewable Energy.

(a) **Purpose.** The purpose of this section is to ensure that an additional 2,000 megawatts (MW) of generating capacity from renewable energy technologies is installed in Texas by 2009 pursuant to the Public Utility Regulatory Act (PURA) §39.904, to establish a renewable energy credits trading program that would ensure that the new renewable energy capacity is built in the most efficient and economical manner, to encourage the development, construction, and operation of new renewable energy resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial resources, to protect and enhance the quality of the environment in Texas through increased use of renewable resources, to respond to customers' expressed preferences for renewable resources by ensuring that all customers have access to providers of energy generated by renewable energy resources pursuant to PURA §39.101(b)(3), and to ensure that the cumulative installed renewable capacity in Texas will be at least 2,880 MW by January 1, 2009.

(b) **Application.** This section applies to power generation companies as defined in §25.5 of this title (relating to definitions), and competitive retailers as defined in subsection (c) of this section. This section shall not apply to an electric utility subject to PURA §39.102(c) until the expiration of the utility's rate freeze period.

(c) **Definitions.**

(1) **Competitive retailer—**A municipally-owned utility, generation and transmission cooperative (G&T), or distribution cooperative that offers customer choice in the restructured competitive electric power market in Texas or a retail electric provider (REP) as defined in §25.5 of this title.

(2) **Compliance period—**A calendar year beginning January 1 and ending December 31 of each year in which renewable energy credits are required of a competitive retailer.

(3) **Designated representative—**A responsible natural person authorized by the owners or operators of a renewable resource to register that resource with the program administrator. The designated representative must have the authority to represent and legally bind the owners and operators of the renewable resource in all matters pertaining to the renewable energy credits trading program.

(4) **Early banking—**Awarding renewable energy credits (RECs) to generators for sale in the trading program prior to the program's first compliance period.

(5) **Existing facilities—**Renewable energy generators placed in service before September 1, 1999.

(6) **Generation offset technology—**Any renewable technology that reduces the demand for electricity at a site where a customer consumes electricity. An example of this technology is solar water heating.

(7) **New facilities—**Renewable energy generators placed in service on or after September 1, 1999. A new facility includes the incremental capacity and associated energy from

an existing renewable facility achieved through repowering activities undertaken on or after September 1, 1999.

(8) **Off-grid generation—**The generation of renewable energy in an application that is not interconnected to a utility transmission or distribution system.

(9) **Program administrator—**The entity approved by the commission that is responsible for carrying out the administrative responsibilities related to the renewable energy credits trading program as set forth in subsection (g) of this section.

(10) **REC offset (offset)**—An REC offset represents one MWh of renewable energy from an existing facility that may be used in place of an REC to meet a renewable energy requirement imposed under this section. REC offsets may not be traded, shall be calculated as set forth in subsection (i) of this section, and shall be applied as set forth in subsection (h) of this section.

(11) **Renewable energy credit (REC or credit)—**An REC represents one megawatt hour (MWh) of renewable energy that is physically metered and verified in Texas and meets the requirements set forth in subsection (e) of this section.

(12) **Renewable energy credit account (REC account)—**An account maintained by the renewable energy credits trading program administrator for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs by a program participant.

(13) **Renewable energy credits trading program (trading program)—**The process of awarding, trading, tracking, and submitting RECs as a means of meeting the renewable energy requirements set out in subsection (d) of this section.

(14) **Renewable energy resource (renewable resource)—** A resource that produces energy derived from renewable energy technologies.

(15) **Renewable energy technology—**Any technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly from the sun, indirectly from the sun, or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, on wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, or waste products from inorganic sources.

(16) **Repowering—**Modernizing or upgrading an existing facility in order to increase its capacity or efficiency.

(17) **Settlement period—**The first calendar quarter following a compliance period in which the settlement process for that compliance year takes place.

(18) **Small producer—**A renewable resource that is less than two megawatts (MW) in size.

(d) **Renewable energy credits trading program (trading program).** Renewable energy credits may be generated, transferred, and retired by renewable energy power generators, competitive retailers, and other market participants as set forth in this section.

(1) The program administrator shall apportion a renewable resource requirement among all competitive retailers as a percentage of the retail sales of each competitive retailer as set

forth in subsection (h) of this section. Each competitive retailer shall be responsible for retiring sufficient RECs as set forth in subsections (h) and (k) of this section to comply with this section. The requirement to purchase RECs pursuant to this section becomes effective on the date each competitive retailer begins serving retail electric customers in Texas.

(2) A power generating company may participate in the program and may generate RECs and buy or sell RECs as set forth in subsection (j) of this section.

(3) RECs shall be credited on an energy basis as set forth in subsection (j) of this section.

(4) Municipally-owned utilities and distribution cooperatives that do not offer customer choice are not obligated to purchase RECs. However, regardless of whether the municipally-owned utility or distribution cooperative offers customer choice, a municipally-owned utility or distribution cooperative possessing renewable resources that meet the requirements of subsection (e) of this section may sell RECs generated by such a resource to competitive retailers as set forth in subsection (j) of this section.

(5) Except where specifically stated, the provisions of this section shall apply uniformly to all participants in the trading program.

(e) **Facilities eligible for producing RECs in the renewable energy credits trading program.** For a renewable facility to be eligible to produce RECs in the trading program it must be either a new facility or a small producer as defined in subsection (c) of this section and must also meet the requirements of this subsection:

(1) A renewable energy resource must not be ineligible under subsection (f) of this section and must register pursuant to subsection (n) of this section;

(2) The facility's above-market costs must not be included in the rates of any utility, municipally-owned utility, or distribution cooperative through base rates, a power cost recovery factor (PCRF), stranded cost recovery mechanism, or any other fixed or variable rate element charged to end users;

(3) For a renewable energy technology that requires fossil fuel, the facility's use of fossil fuel must not exceed 2.0% of the total annual fuel input on a British thermal unit (BTU) or equivalent basis;

(4) The output of the facility must be readily capable of being physically metered and verified in Texas by the program administrator. Energy from a renewable facility that is delivered into a transmission system where it is commingled with electricity from non-renewable resources can not be verified as delivered to Texas customers. A facility is not ineligible by virtue of the fact that the facility is a generation-offset, off-grid, or on-site distributed renewable facility if it otherwise meets the requirements of this section; and

(5) For a municipally owned utility operating a gas distribution system, any production or acquisition of landfill gas that is directly supplied to the gas distribution system is eligible to produce RECs based upon the conversion of the thermal energy in BTUs to electric energy in kWh using for the conversion factor the systemwide average heat rate of the gas-fired units of the combined utility's electric system as measured in BTUs per kWh.

(6) For industry-standard thermal technologies, the RECs can be earned only on the renewable portion of energy production. Furthermore, the contribution toward statewide renewable capacity megawatt goals from such facilities would be equal to the fraction of the facility's annual MWh energy output from renewable fuel multiplied by the facility's nameplate MW capacity.

(f) **Facilities not eligible for producing RECs in the renewable energy credits trading program.** A renewable facility is not eligible to produce RECs in the trading program if it is:

(1) A renewable energy capacity addition associated with an emissions reductions project described in Health and Safety Code §382.05193, that is used to satisfy the permit requirements in Health and Safety Code §382.0519;

(2) An existing facility that is not a small producer as defined in subsection (c) of this section; or

(3) An existing fossil plant that is repowered to use a renewable fuel.

(g) **Responsibilities of program administrator.** No later than June 1, 2000, the commission shall approve an independent entity to serve as the trading program administrator. At a minimum, the program administrator shall perform the following functions:

(1) Create accounts that track RECs for each participant in the trading program;

(2) Award RECs to registered renewable energy facilities on a quarterly basis based on verified meter reads;

(3) Assign offsets to competitive retailers on an annual basis based on a nomination submitted by the competitive retailer pursuant to subsection (n) of this section;

(4) Annually retire RECs that each competitive retailer submits to meet its renewable energy requirement;

(5) Retire RECs at the end of each REC's three-year life;

(6) Maintain public information on its website that provides trading program information to interested buyers and sellers of RECs;

(7) Create an exchange procedure where persons may purchase and sell RECs. The exchange shall ensure the anonymity of persons purchasing or selling RECs. The program administrator may delegate this function to an independent third party. The commission shall approve any such delegation;

(8) Make public each month the total energy sales of competitive retailers in Texas for the previous month;

(9) Perform audits of generators participating in the trading program to verify accuracy of metered production data;

(10) Allocate the renewable energy responsibility to each competitive retailer in accordance with subsection (h) of this section; and

(11) Submit an annual report to the commission. Beginning with the program's first compliance period, the program administrator shall submit a report to the commission on or before April 15 of each calendar year. The report shall contain information

pertaining to renewable energy power generators and competitive retailers. At a minimum, the report shall contain:

(A) the amount of existing and new renewable energy capacity in MW installed in the state by technology type, the owner/operator of each facility, the date each facility began to produce energy, the amount of energy generated in megawatt-hours (MWh) each quarter for all capacity participating in the trading program or that was retired from service; and

(B) a listing of all competitive retailers participating in the trading program, each competitive retailer's renewable energy credit requirement, the number of offsets used by each competitive retailer, the number of credits retired by each competitive retailer, a listing of all competitive retailers that were in compliance with the REC requirement, a listing of all competitive retailers that failed to retire sufficient REC requirement, and the deficiency of each competitive retailer that failed to retire sufficient RECs to meet its REC requirement.

(h) **Allocation of REC purchase requirement to competitive retailers.** The program administrator shall allocate REC requirements among competitive retailers. Any renewable capacity that is retired before January 1, 2009 or any capacity shortfalls that arise due to purchases of RECs from out-of-state facilities shall be replaced and incorporated into the allocation methodology set forth in this subsection. Any changes to the allocation methodology to reflect replacement capacity shall occur two compliance periods after which the facility was retired or capacity shortfall occurred. The program administrator shall use the following methodology to determine the total annual REC requirement for a given year and the final REC requirement for individual competitive retailers:

(1) The total statewide REC requirement for each compliance period shall be calculated in terms of MWh and shall be equal to the renewable capacity target multiplied by 8,760 hours per year, multiplied by the appropriate capacity conversion factor set forth in subsection (i) of this section. The renewable energy capacity targets for the compliance period beginning January 1, of the year indicated shall be:

(A) 400 MW of new resources in 2002;

(B) 400 MW of new resources in 2003;

(C) 850 MW of new resources in 2004;

(D) 850 MW of new resources 2005;

(E) 1,400 MW of new resources in 2006;

(F) 1,400 MW of new resources in 2007;

(G) 2,000 MW of new resources in 2008; and

(H) 2,000 MW of new resources in 2009 through 2019.

(2) The final REC requirement for an individual competitive retailer for a compliance period shall be calculated as follows:

(A) Each competitive retailer's preliminary REC requirement is determined by dividing its total retail energy sales in Texas by the total retail sales in Texas of all competitive retailers, and multiplying that percentage by the total statewide REC requirement for that compliance period.

(B) The adjusted REC requirement for each competitive retailer that is entitled to an offset is determined by reducing its preliminary REC requirement by the offsets to which it qualifies, as determined under subsection (i) of this section, with the maximum reduction equal to the competitive retailer's preliminary REC requirement. The total reductions for all competitive retailers is equal to the total usable offsets for that compliance period.

(C) Each competitive retailer's final REC requirement for a compliance period shall be increased to recapture the total usable offsets calculated under subparagraph (B) of this paragraph. The additional REC requirement shall be calculated by dividing the competitive retailer's adjusted REC requirement by the total adjusted REC requirement of all competitive retailers. This fraction shall be multiplied by the total usable offsets for that compliance period and this amount shall be added to the competitive retailer's adjusted REC requirement to produce the competitive retailer's final REC requirement for the compliance period.

(i) **Nomination and calculation of REC offsets.**

(1) A REP, municipally-owned utility, G&T cooperative, distribution cooperative, or an affiliate of a REP, municipally-owned utility, or distribution cooperative, may apply

offsets to meet all or a portion of its renewable energy purchase requirement, as calculated in subsection (h) of this section, only if those offsets are nominated in a filing with the commission by June 1, 2001. A G&T may nominate the combined offsets for itself and its member distribution cooperatives upon the presentation of a resolution by its Board authorizing it to do so.

(2) The commission shall verify any designations of REC offsets and notify the program administrator of its determination by December 31, 2001.

(3) REC offsets shall be equal to the average annual MWh output of an existing resource for the years 1991-2000 or the entire life of the existing resource, whichever is less.

(4) REC offsets qualify for use in a compliance period under subsection (h) of this section only to the extent that:

(A) The resource producing the REC offset has continuously since September 1, 1999 been owned by or its output has been committed under contract to a utility, municipally-owned utility, or cooperative nominating the resource under paragraph (1) of this subsection or, if the resource has been committed under a contract that expired after September 1, 1999 and before January 1, 2002, it is owned by or its output has been committed under contract to a utility, municipally-owned utility, or cooperative on January 1, 2002; and

(B) The facility producing the REC offsets is operated and producing energy during the compliance period in a manner consistent with historic practice.

(5) If the production from a facility producing the REC offset energy ceases for any reason, the competitive retailer may no longer claim the REC offset against its REC requirement.

(j) **Calculation of capacity conversion factor.** The capacity conversion factor used by the program administrator to allocate credits to competitive retailers shall be calculated as follows:

(1) The capacity conversion factor (CCF) shall be administratively set at 35% for 2002 and 2003, the first two compliance periods of the program.

(2) During the fourth quarter of the second compliance year (2003), the CCF shall be readjusted to reflect actual generator performance data associated with all renewable resources in the trading program. The program administrator shall adjust the CCF every two years thereafter and shall:

(A) be based on all renewable energy resources in the trading program for which at least 12 months of performance data is available;

(B) represent a weighted average of generator performance;

(C) use all valid performance data that is available for each renewable resource; and

(D) ensure that the renewable capacity goals are attained.

(k) **Production and transfer of RECs.** The program administrator shall administer a trading program for renewable energy credits in accordance with the requirements of this subsection.

(1) A REC will be awarded to the owner of a renewable resource when a MWh is metered at that renewable resource. A generator producing 0.5 MWh or greater as its last unit

generated should be awarded one REC on a quarterly basis. The program administrator shall record the amount of metered MWh and credit the REC account of the renewable resource that generated the energy on a quarterly basis.

(2) The transfer of RECs between parties shall be effective only when the transfer is recorded by the program administrator.

(3) The program administrator shall require that RECs be adequately identified prior to recording a transfer and shall issue an acknowledgement of the transaction to parties upon provision of adequate information. At a minimum, the following information shall be provided:

(A) identification of the parties;

(B) REC serial number, REC issue date, and the renewable resource that produced the REC;

(C) the number of RECs to be transferred; and

(D) the transaction date.

(4) A competitive retailer shall surrender RECs to the program administrator for retirement from the market in order to meet its REC allocation for a compliance period. The program administrator will document all REC retirements annually.

(5) On or after each April 1, the program administrator will retire RECs that have not been retired by competitive retailers and have reached the end of their three-year life.

(6) The program administrator may establish a procedure to ensure that the award, transfer, and retirement of credits are accurately recorded.

(l) **Settlement process.** Beginning in January 2003, the first quarter following the compliance period shall be the settlement period during which the following actions shall occur:

(1) By January 31, the program administrator will notify each competitive retailer of its total REC requirement for the previous compliance period as determined pursuant to subsection (h) of this section.

(2) By March 31, each competitive retailer must submit credits to the program administrator from its account equivalent to its REC requirement for the previous compliance period. If the competitive retailer has insufficient credits in its account to satisfy its obligation, and this shortfall exceeds the applicable deficit allowance as set forth in subsection (m)(2) of this section, the competitive retailer is subject to the penalty provisions in subsection (o) of this section.

(m) **Trading program compliance cycle.**

(1) The first compliance period shall begin on January 1, 2002 and there will be 18 consecutive compliance periods. Early banking of RECs is permissible and may commence no earlier than July 1, 2001. The program's first settlement period shall take place during the first quarter of 2003.

(2) A competitive retailer may incur a deficit allowance equal to 5.0% of its REC requirement in 2002 and 2003 (the first two compliance periods of the program). This 5.0% deficit allowance shall not apply to entities that initiate customer choice after

2003. During the first settlement period, each competitive retailer will be subject to a penalty for any REC shortfall that is greater than 5.0% of its REC requirement under subsection (h) of this section. During the second settlement period, each competitive retailer will be subject to the penalty process for any REC shortfall greater than 5.0% of the second year REC allocation. All competitive retailers incurring a 5.0% deficit pursuant to this subsection must make up the amount of RECs associated with the deficit in the next compliance period.

(3) The issue date of RECs created by a renewable energy resource shall coincide with the beginning of the compliance year in which the credits are generated. All RECs shall have a life of three compliance periods, after which the program administrator will retire them from the trading program.

(4) Each REC that is not used in the year of its creation may be banked and is valid for the next two compliance years.

(5) A competitive retailer may meet its renewable energy requirements for a compliance period with RECs issued in or prior to that compliance period which have not been retired.

(n) **Registration and certification of renewable energy facilities.** The commission shall register and certify all renewable facilities that will produce either REC offsets or RECs for sale in the trading program. To be awarded RECs or REC offsets, a power generator must complete the registration process described in this subsection. The program administrator shall not award offsets or credits for energy produced by a power generator before it has been certified by the commission.

(1) The designated representative of the generating facility shall file an application with the commission on a form approved by the commission for each renewable energy generation facility. At a minimum, the application shall include the location, owner, technology, and rated capacity of the facility and shall demonstrate that the facility meets the resource eligibility criteria in subsection (e) of this section.

(2) No later than 30 days after the designated representative files the certification form with the commission, the commission shall inform both the program administrator and the designated representative whether the renewable facility has met the certification requirements. At that time, the commission shall either certify the renewable facility as eligible to receive either RECs or offsets, or describe any insufficiencies to be remedied. If the application is contested, the time for acting is extended by 30 days.

(3) Upon receiving notice of certification of new facilities, the program administrator shall create an REC account for the designated representative of the renewable resource.

(4) The commission may make on-site visits to any certified unit of a renewable energy resource and may decertify any unit if it is not in compliance with the provisions of this subsection.

(5) A decertified renewable generator may not be awarded RECs. However, any RECs awarded by the program administrator and transferred to a competitive retailer prior to the decertification remain valid.

(o) **Penalties and enforcement.** If by April 1 of the year following a compliance year it is determined that a competitive retailer with an allocated REC purchase requirement has insufficient credits to satisfy its allocation, the competitive retailer shall be subject to the administrative penalty provisions of PURA §15.023 as specified in this subsection.

(1) Except as provided in paragraph (4) of this subsection, a penalty will be assessed for that portion of the deficient credits.

(2) The penalty shall be the lesser of $50 per MWh or, upon presentation of suitable evidence of market value by the competitive retailer, 200% of the average market value of credits for that compliance period.

(3) There will be no obligation on the competitive retailer to purchase RECs for deficits, whether or not the deficit was within or was not within the competitive retailer's reasonable control, except as set forth in subsection (m)(2) of this section.

(4) In the event that the commission determines that events beyond the reasonable control of a competitive retailer prevented it from meeting its REC requirement there will be no penalty assessed.

(5) A party is responsible for conducting sufficient advance planning to acquire its allotment of RECs. Failure of the spot or short-term market to supply a party with the allocated number of RECs shall not constitute an event outside the competitive retailer's reasonable control. Events or circumstances that are outside of a party's reasonable control may include weather-related damage, mechanical failure, lack of transmission

capacity or availability, strikes, lockouts, actions of a governmental authority that adversely effect the generation, transmission, or distribution of renewable energy from an eligible resource under contract to a purchaser.

(p) **Renewable resources eligible for sale in the Texas wholesale and retail markets.** Any energy produced by a renewable resource may be bought and sold in the Texas wholesale market or to retail customers in Texas and marketed as renewable energy if it is generated from a resource that meets the definition in subsection (c)(14) of this section.

(q) **Periodic review.** The commission shall periodically assess the effectiveness of the energy-based credits trading program in this section to maximize the energy output from the new capacity additions and ensure that the goal for renewable energy is achieved in the most economically-efficient manner. If the energy-based trading program is not effective, performance standards will be designed to ensure that the cumulative installed renewable capacity in Texas meets the requirements of PURA §39.904.

This agency hereby certifies that the rule, as adopted, has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that rule §25.173 relating to Goal for Renewable Energy is hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 20th DAY OF DECEMBER 1999.

PUBLIC UTILITY COMMISSION OF TEXAS

Chairman Pat Wood, III

Commissioner Judy Walsh

Commissioner Brett A. Perlman