The Public Utility Commission of Texas (commission) adopts new §25.261 relating to Stranded Cost Recovery of Environmental Cleanup Costs with changes to the proposed text as published in the May 12, 2000, Texas Register (25 TexReg 4264, graphic 25 TexReg 4365). The new rule is adopted under Project Number 21406. The rule is necessary to implement Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated, §39.263. PURA §39.263 allows recovery of capital costs incurred by an electric utility or affiliated power generation company to improve air quality in accordance with the provisions of PURA §39.264. The implementation of PURA §39.264 and regulatory programs designed to achieve compliance with national ambient air quality standards fall under the auspices of the Texas Natural Resource Conservation Commission (TNRCC).

A workshop to develop price projections used to determine cost of replacement generating capacity in subsection (c)(2) will be held at 9:30 a.m. on Monday, September 11, 2000, in Room 1-111, 1st Floor, William B. Travis Building, 1701 North Congress, Austin, Texas, 78701. The commission anticipates that staff's proposed price projections will be made available for public comment on the commission's website at www.puc.state.tx.us/rules/rulemake/21406/21406.cfm on September 1, 2000, to allow interested parties an opportunity to review staff's proposal prior to the workshop. Shortly after the workshop, a price projection methodology will be submitted to the commission for approval.

The commission anticipates that a draft methodology for calculating the impact of potential future environmental regulations on the cost of retrofitting an electric generating facility will be posted by commission staff on the commission's website on or before September 15, 2000, to allow interested parties to review staff's proposal prior to the workshop. In addition, a workshop to develop a methodology for calculating the impact of costs to meet pre-2011 environmental regulatory requirements on the cost-effectiveness analysis will be held on September 21, 2000, at 9:30 a.m. in the Commissioner's Hearing Room, 7th Floor, William B. Travis Building, 1701 North Congress, Austin, Texas, 78701. The commission anticipates that shortly after this workshop, a draft methodology will be available for a brief period for review and comment. The commission anticipates that it will approve a methodology for calculating the impact of future environmental regulatory requirements on the cost-effectiveness analysis at the October 5, 2000, open meeting.

A public hearing on the proposed section was held at commission offices on June 22, 2000. Representatives from Public Citizen, Clean Water Action, Sustainable Energy and Economic Development Coalition (SEED Coalition), Sierra Club, Environmental Defense, and Reliant Energy HL&P attended the hearing and provided comments. To the extent that these comments differ from the submitted written comments, such comments are summarized herein.

In addition to the comments received at the public hearing, the commission received written comments on the proposed new section from Calpine Corporation (Calpine); Center for Energy and Economic Development (CEED); Central and Southwest Operating Companies (CSW); Entergy Gulf States, Inc. (EGSI); Environmental Defense; National Park Service, United States

Department of Interior (Park Service); Nucor Steel (Nucor); Office of Public Utility Counsel (OPC); Public Citizen, the Sustainable Energy and Economic Development Coalition, Texas Campaign for the Environment, and Clean Water Action (collectively Public Citizen); Reliant Energy HL&P (Reliant); Texas Industrial Energy Consumers (TIEC); Texas Ratepayers' Organization to Save Energy, Consumers Union Southwest Regional Office, Texas Legal Services Center, and American Association of Retired Persons (AARP) (collectively Texas ROSE); TXU Electric Company (TXU); and TNRCC.

*Comments on specific questions in the preamble of the proposed rule*

In the preamble, the commission requested that interested parties address eight issues related to the implementation and final development of the proposed rule. The parties' comments on the issues and the commission's responses thereto are summarized below.

*Issue 1:* *Under the proposed rule, an application for approval of an electric utility's or power generation company's determination regarding the most cost-effective means of meeting the requirements of PURA §39.264 or achieving compliance with national ambient air quality standards, or both, is deemed approved if no objection is filed within 60-days of filing of a complete application and completion of notice. Is the proposed 60-day period for objecting to an application for a cost-effectiveness determination in proposed subsection (e)(3) a sufficient period of time for an interested party to review the application and file an objection, if needed?*

Most utility respondents favored a 60-day or shorter deadline for objecting to an application for a cost-effectiveness determination. CSW and Reliant did not object to the 60-day timeline because, due to the limited issues involved in the filings, interested parties will be able to determine fairly quickly whether they object to a particular application. TXU recommended a 30-day timeline for filing objections because an expedited proceeding is necessary to meet the PURA deadlines for cost recovery.

Comments from non-utilities were generally supportive of a 60-day or longer objection period. Nucor and TIEC recommended a 120-day period based on their concerns that 60 days does not provide adequate time for an interested party to determine whether it objects to a particular application.

Calpine and Texas ROSE generally supported a 60-day objection period. Calpine commented that 60 days allows for two rounds of discovery before the objection deadline. In its reply comments, Calpine noted that decision-making by interested parties could be expedited if the time to respond to requests for information was reduced from the standard 20-day timeline in commission rules to ten days. Texas ROSE commented that a 90-day objection period would be necessary if filings are not staggered, but with staggering a 60-day period would be adequate.

The commission believes that a 60-day objection period provides an interested party an adequate opportunity to investigate an application and determine whether it objects to the application. If needed, commission procedural rules provide an avenue for shortening the response time for requests for information. The commission does not believe a 30-day objection period provides interested parties an adequate opportunity to evaluate an application and determine whether objection is necessary. A longer objection period would unnecessarily delay ruling on a utility's application. Further, the commission does not agree that mandatory staggering of application filings is required. Relatively few applications will be filed under this section and, based on current information, the commission does not anticipate that all applications will be filed at the same time. In fact, some utilities may forgo filing an initial application for approval of an emissions reduction plan, opting instead to seek both plan and expenditure approval in the true-up proceeding. No changes were made in response to these comments.

*Issue 2.* *In the event that an application for approval of a cost-effectiveness determination is protested, the proposed rule requires that the commission render a decision on the application within one year of filing. Should a different time limit be placed on the cost-effectiveness determination than the one-year period specified in proposed subsection (e)(4)?*

CSW, EGSI, and TXU commented that the proposed 1-year time limit for commission review and approval of an emissions reduction plan is much too long because the length of time required for commission approval of a plan will erode the time available to a utility to meet the deadlines in PURA §39.263(a) and (b) for incurring costs. CSW and TXU advocate a 180-day time limit, which CSW notes would be consistent with the expedited review afforded to transmission projects deemed critical by the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ISO). EGSI recommends a 90-day review period.

Reliant commented that the bifurcated approval process of the proposed rule (approve emissions reduction plan first, then approve expenditures in subsequent true-up) is unnecessary. Review of the reasonableness and cost-effectiveness of an emissions reduction plan should take place only in the utility's 2004 true-up proceeding. In reply comments Reliant proposed that the utility should have the choice of a one-step or two-step review process. This proposal was supported by EGSI in its reply comments.

Calpine also recommended that the commission adopt a 180-day time frame to process applications but reserve the right to extend the proceeding another 180 days upon a showing of good cause. Calpine stated that an expedited approval process is warranted due to the deadlines in PURA. In reply comments, Calpine asserted that delay in approval of an emissions reduction plan is not in the best interests of any party. Utilities will need time to respond to the commission's cost-effectiveness determination and lead times for some equipment orders require utilities to place orders fairly soon.

Texas ROSE and TIEC both agreed that a one-year period for review of an emissions reduction plan is appropriate. Texas ROSE noted that the long-term implications and costs associated with these filings necessitate a thoughtful and thorough review.

Nucor objected to placing any time limit on review of a proposed emissions reduction plan. Nucor noted that PURA does not include an application review deadline. In reply comments Nucor argued that the utilities' alleged need for certainty regarding approval of emission reduction plans is overblown. Investment decisions associated with emissions reductions are no different than traditional investment decisions subject to after-the-fact prudence review. In the future unregulated market, utilities will not have certainty regarding any of their investment decisions.

The commission is persuaded by the comments suggesting that a 180-day review period, with an option to extend for good cause, is appropriate for emissions reductions plans because of the deadlines in PURA §39.263(a) and (b). The commission has also determined that certainty regarding the fate of specific plants is needed reasonably soon, before 2004. Therefore, all utilities that plan to seek recovery of stranded environmental clean-up costs will be required to file an application for a cost-effectiveness determination under subsection (e) of the rule on or before January 10, 2003. The commission has revised the rule in accordance with its response to these comments.

*Issue 3:* *The proposed rule does not allow recovery of costs associated with purchasing emissions allowances, largely because an open market for purchasing allowances does not presently exist. In the absence of an open market, verifying the market value of an emission allowance is problematic. If the commission were to allow recovery of capital costs associated with purchasing allowances, what mechanisms could be used to determine whether allowance purchases are prudent if spot market prices are not available for comparison? How could the commission ensure that recovery is not allowed both for a utility (Utility A) installing equipment to reduce emissions and another utility purchasing* *allowances from utility A? In other words, what methodologies could be used to track traded allowances to ensure against double recovery?*

Calpine, Environmental Defense, Nucor, Public Citizen, Texas ROSE, and TIEC opposed recovery of costs associated with buying emissions allowances. EGSI, Reliant, and TXU commented in favor of allowing recovery of emissions allowance purchase costs.

Nucor commented that emissions allowance purchase costs are operation and maintenance expenses, not capital costs incurred by an electric utility to improve air quality. Because cost recovery is allowed only for capital costs incurred by an electric utility to improve air quality, cost recovery for emissions allowance purchases should not be allowed under the rule. TIEC claimed that whereas capital costs are fixed in value, the value of emissions allowances can vary because the allowances are tradable. The fluctuating value of emissions allowances precludes them from being recovered as stranded costs under PURA §39.263. In reply comments, TIEC reiterated the distinction between invested capital, which represents fixed, sunk costs that are valued at original cost less depreciation, and emissions allowances, which are tradable commodities that can fluctuate in value, depending on market conditions. Calpine stated that emissions allowances should be expensed, rather than capitalized, as they are beneficial only in the year they are used. Calpine further commented that recovery of allowance purchases is not necessary given that the proposed rule allows for the allocation of compliance costs between multiple facilities.

Calpine also asserted that a comprehensive and burdensome registration and tracking system would be needed to ensure that allowance costs are not double-counted if recovery of emissions allowance purchase costs is permitted. Calpine also expressed competitive concerns. It observed that in many regions allowances will already be concentrated among incumbent utilities, and cautioned that permitting the recovery of costs of allowance purchases could increase concentration levels and decrease potential competition in the region. In reply comments Texas ROSE also asserted that permitting recovery of emissions allowance purchase costs would exacerbate the market power situation.

Texas ROSE asserted that the sponsors of Senate Bill 7 (SB 7), 76th Legislative Session, never indicated that the law would permit the continued operation of a grandfathered plant at current emissions levels due to the use of trading credits or other allowances from other non-utility facilities. Texas ROSE recommended that the rule affirmatively state that offsets, emissions allowances, emissions trading, and trading credits as approved by TNRCC are legitimate emissions reduction strategies but that the costs of purchased emissions allowances are ineligible for stranded cost recovery.

Environmental Defense opposed recovery of costs associated with purchasing emissions allowances unless there is a mechanism in place to prevent double-recovery. Nucor stated that if the commission decides to permit cost recovery for emissions allowance purchases, the questions posed concerning valuation and double-recovery would need to be addressed on a utility-by-utility basis.

EGSI expressed the belief that the costs of purchasing emissions allowances should be recoverable. EGSI argued that disallowing the recovery of emissions-allowance purchase costs might bias cost-effectiveness analyses toward capital intensive solutions. With respect to the absence of a current market for allowances, EGSI recommended that a process be implemented to project emissions allowance prices for use in comparing alternatives. Furthermore, EGSI contended that double-recovery should pose no problem because the value of excess allowances would offset recovery of abatement costs.

Reliant claimed that the commission, to give effect to statutory language allowing recovery of costs to offset emissions, should allow recovery of costs associated with purchasing allowances. The rule should be clarified to allow utilities to over-control at one unit and use the excess reductions generated through over-control to offset emissions at another unit or units in that utility's system. Reliant also argued that sales of credits would not result in a double-recovery problem because the market value of the utility will increase if additional emissions credits result from over-compliance at a particular utility. For example, suppose Utility A needs to reduce its emissions on a particular unit by 300 tons. If Utility A installs controls that reduce emissions by 500 tons, Utility A would have 200 tons worth of offsets to sell. The net book value of the unit would increase by the costs incurred for the retrofit, but the market value of the asset would also be increased to reflect the value of the 200 tons worth of offsets that Utility A could sell. Therefore, Utility A's stranded costs would be unaffected. If Utility B then purchased 200 tons worth of offsets from Utility A as part of its air quality control strategy, Utility B would include that amount as invested capital and its associated market value would increase. The higher market value would be reflected in the true-up as a lower excess cost over market (ECOM).

Therefore, there is no double-recovery, as the market will adjust the valuation of a utility to reflect the action taken to buy or sell allowances.

TXU also suggested that over-recovery would not be a problem if an up-front proceeding were held to determine the amount of reductions that must be achieved by a utility at each of its units. With such a determination, the possibility of double-recovery would be eliminated. A utility would certainly be free to take its chances on a future emissions-allowance market and over-comply in the hopes of profiting from its sales of allowances, but the utility would not receive cost recovery for installing the equipment that results in overcompliance.

In reply comments, Calpine disputed the contention that the commission need not be concerned about the possibility of double recovery of costs. If, for example, a utility over-complies and sells allowances to another utility before the true-up proceeding, the proceeding may not capture the value associated with over-compliance. And if the market is not perfectly efficient, the market value of the power generation company may not reflect the full value of any excess emissions credits that may be created. Therefore, a comprehensive tracking and registration program would be needed to prevent double-recovery if recovery of emissions allowance purchase costs is permitted. Calpine also disputed claims that cost-effectiveness should be determined on a system-wide basis. Calpine asserted that PURA §39.264 requires a reduction in emissions on a facility-by-facility basis.

In reply comments, Nucor added that a utility may not recover excessive costs incurred with a retrofit when purchasing emissions allowances would be more cost-effective because PURA §39.263 directs the recovery of such costs only for the most cost-effective option.

EGSI in reply comments restated its contention that double recovery can be avoided by offsetting the value of allowances sold by a utility against recovery of abatement costs. EGSI also stated that inefficient or speculative over-compliance can be discouraged by permitting recovery of costs associated with over-compliance only when the company has made prior contractual arrangements to trade allowances with another affected company.

In its reply, Reliant asserted that the provisions of PURA §39.263 allowing recovery of costs incurred "to offset or reduce the emission of airborne contaminants" clearly evidence the legislature's intent to allow for the recovery of capital costs incurred to offset emissions from electric generating facilities. Therefore, Reliant argued, a utility could develop a plan to reduce emissions on a system-wide basis. Reliant also stated that such a plan is consistent with existing TNRCC plans, which require the attainment of a system-wide average emission rate, and with TNRCC's contemplated mass-cap emissions limitation program.

The commission concludes that allowing recovery for purchased emissions allowances has the potential to reduce overall compliance costs because the cost of purchased allowances may be lower in some cases than the cost of retrofitting a unit. It is in the public interest to minimize costs associated with air quality improvements that will be eligible for recovery through stranded costs. The commission will allow recovery of the costs of purchasing allowances only to the extent that the utility shows that purchasing allowances is the best cost-minimization strategy under the rule. Concerns about tracking emissions allowances are misplaced. Tracking of allowances will not be necessary because a utility will not be allowed to recover expenditures in excess of those necessary to achieve required emissions reductions at a particular unit. A utility that over-complies will not be allowed cost recovery to the extent of over-compliance but may be able to sell allowances that become available because of over-compliance.

The commission has also determined that the expenditures made to purchase allowances can be treated as capital expenditures. The Internal Revenue Service has concluded that purchases of sulfur dioxide allowances issued by the Environmental Protection Agency (EPA) under the Clean Air Act Amendments are properly treated as capital expenditures. *See* Internal Revenue Service Rev. Proc. 92-91. Further, the commission has the authority to determine whether an expenditure should be expensed or capitalized. *State of Texas v. Public Utility Commission* 883 S.W.2d 190, 195 (Tex. 1994).

The commission does not agree that PURA §39.063 prohibits recovery of allowance purchase costs because the statute specifically refers to costs applied to offset or reduce emissions. Further, the commission does not agree that the statute requires cost effectiveness to be determined on a facility-by-facility basis. The commission finds no language in the statute that would preclude making cost-effectiveness determinations on a system-wide basis. The commission believes that evaluating costs on a system-wide basis will expand the compliance options available to the utility and may result in lower overall compliance costs. The proposed rule has been revised to allow recovery of emissions allowance purchase costs.

*Issue 4:* *Under the proposed rule, the cost of replacement generating capacity is determined from the electric utility's average purchased power cost for the three most current years and the average amount of generation for the same three years. Should the replacement generating capacity be based on a projected market price because the analysis deals with future costs? Included in the commission-approved excess cost over market (ECOM) model are market prices for power. Should these prices be used in the comparative analysis instead of the average historical prices? Alternatively, should the commission rely on market-price estimates proposed by the utility in its calculation of ECOM for setting a competitive transition charge?*

With the exception of Nucor, none of the initial commenters expressed support for the use of historical price figures. Other commenters expressed support for future cost projections based on the ECOM model or other methodologies.

EGSI commented that historical purchased power costs may be based on contractual arrangements that are not reflective of current market conditions. Also, average purchased power costs for a utility system may not be appropriate for evaluating only one unit of the system. EGSI therefore recommended that the cost of replacement generating capacity be benchmarked against the capital cost of a new plant. These costs should reflect all fixed costs on a dollar per kilowatt-year ($/kW-year) basis and variable costs on a dollar per megawatt-hour ($/MWh) basis to allow comparison of unit specific investment decisions.

CSW commented that the proposed §25.261(c)(2) represents a determination of energy cost only, not replacement generating capacity. CSW also commented that historical purchased power costs do not provide an indication of market price for capacity at the point in time retirement is considered. Historical purchased power costs would also bias the analysis because they completely ignore the capital-related costs of purchasing generation services. The cost of replacement generating capacity should be based on the all-in cost filed in each utility's ECOM case because these market prices reflect the best available current estimate of expected future market prices for each company. CSW did not agree with prices derived by commission staff in its application of the ECOM model because capacity cost information used by commission staff is stale and arbitrary adders are included for fuel diversity and ancillary services that are not representative of the current market.

TIEC agreed that projected market prices should be used in conducting comparative analyses. Unadjusted historical purchased power costs would probably not provide an accurate estimate of future replacement generation costs. Also, the ECOM model may not properly account for site-specific factors. The basic approach to quantifying the cost of replacement capacity in the ECOM model should be preserved, but the commission should permit variance in the input parameters to more accurately reflect site-specific circumstances.

TXU recommended that the rule include a standardized approach for performing the retrofit-versus-retirement analysis. The analysis should rely on known data modified as necessary to account for a competitive market. The calculation of expected purchased power prices should include fundamental reliance on the ECOM model to promote consistency between different stranded cost analyses.

Texas ROSE requested that the commission define the phrase "taking into account the cost of replacement generating capacity" in PURA §39.263. Texas ROSE does not believe this phrase is intended to allow the utilities to have the cost of replacement generation factored into the retirement versus retrofit decision because cost recovery for new generating plants is not appropriate in the deregulated market. The cost comparison analysis should take into account the cost to consumers, not utilities, of replacement generating capacity. Capacity shortages or market power consolidation resulting from retirement should be addressed.

Public Citizen supported use of projected costs over the 2003-2008 time frame because it anticipates that the market price of power will drop from current levels. The commission should establish a set of standard market prices based on contracted prices for that period during 2002.

Environmental Defense supported use of replacement costs derived from the ECOM model.

Nucor supported use of historical costs, subject to review to ensure they are reasonable. If historical costs are not utilized, there should be a rebuttable presumption in their favor.

Reliant commented that replacement power costs must be analyzed on a market basis. Given the limited amount of market price data available for ERCOT, price projections should be developed based on the relationship between supply and demand.

In its reply, TXU stated that the purchase of replacement generating capacity must be included in the evaluation of retirement costs because the statute clearly requires that it be considered.

In its reply, Reliant suggested that the methodology for estimating replacement capacity should consider three points: (1) the use of historical purchased power costs and historical generation levels for future projections is not accurate. Reasonable estimates must be developed using explicit modeling taking into account fluctuations in expected demand and supply conditions over time; (2) estimates of the cost of replacement capacity must incorporate the cost of new capacity; and (3) seasonal and hourly price differentiation must be considered. The use of a formula that shapes annual ECOM prices using an adjustment factor derived from other markets is not appropriate. Instead, price shaping should be based on forward-looking demand and supply characteristics specific to the ERCOT market, which can be developed by performing production cost simulation analyses.

In reply comments, Calpine argued that any forecasted price will undoubtedly prove inaccurate. Therefore, the use of purchased energy costs from the commission's fuel report represents a reasonable approach for determining replacement capacity costs and should be adopted. Calpine recommended that if the commission determines that a forecasted market price is more appropriate than the historical price proposed in the rule, replacement power costs should be determined based on three major factors: (1) the amount of capacity being replaced; (2) the remaining useful life of the unit to be replaced in a competitive market; and (3) the price of power in a competitive market. The amount of capacity should be based on the average amount of capacity provided by the unit over the last three years. Calpine suggested use of proxies for replacement power costs depending upon the anticipated remaining useful life of a unit: (1) if the remaining useful life is less than five years, use the average cost of firm power for the months of June through September for the most recent year available in the unit's region; (2) if remaining useful life is between five and ten years, use the costs associated with a simple cycle combustion turbine; and (3) if the remaining useful life is ten years or more, use the costs associated with a combined cycle combustion turbine.

In reply comments, TIEC recommended that the basic approach to the cost-benefit analysis should follow the ECOM model, and the model should incorporate utility-specific inputs that reflect the specific circumstances surrounding each unit. It is inappropriate to apply market prices resulting from utility ECOM model assumptions, as suggested by CSW, because the commission has already rejected this approach in Docket Number 22344, *Generic Issues Associated with Application for Approval of Unbundled Cost of Service Rate Pursuant to PURA Section 39.201 and Public Utility Commission Subst. R. 25.344*. The commission should reject the TXU proposal. TXU offered no evidence to support its assertion that its proposed inputs should be generically applied to all utility cost-benefit analyses. The inflation escalators applied in the cost-benefit analyses could be determined on a generic basis in a generic hearing.

As discussed in more detail in the commission's response to comments regarding subsection (c), the commission has determined that the purchased power component of the cost of replacement generating capacity should be determined based on future price projections. The ECOM model does provide a future price projection, but it is only for a natural gas-fired base load unit.

Projections for peaking and intermediate units also need to be developed. The commission believes such projections can be developed using pricing experience in deregulated regions with adjustments to reflect circumstances within ERCOT.

*Issue 5:* *The commission recognizes that given the configuration of the electric grid at present and in the near future, certain electric generating facilities within the Electric Reliability Council of Texas (ERCOT) area need to operate for the next three to seven years to maintain the reliability of the electric system, despite their age and inefficient operating characteristics. Where a facility is needed to maintain the reliability of the electric system and is designated by the ERCOT Independent System Operator (ISO) as a reliability must-run unit (RMR), the commission believes that a different analysis must be employed that takes into consideration the benefits of the plant to electric customers. One way of doing so is to explicitly consider customer benefits when comparing retirement and retrofit options. It might also be reasonable to simply assume that the customer benefits of RMR units are significant enough that an explicit assessment of these benefits is not necessary. If this assumption were used, only retrofit options for an RMR unit would be evaluated. How should the commission analyze retirement/retrofit options for RMR units? If it uses a customer benefit analysis, are there accepted values for the customer benefits of electric service that could be incorporated into the rule?*

TXU commented that a standardized analysis should be used by all utilities. A cost must be assigned to the social impact of inadequate reliability, which could be the cost of transmission system upgrades. The economic comparison for reliability units is between (1) the cost of operating the unit with retrofit; and (2) the cost of obtaining replacement generating capacity, retirement cost, and necessary transmission upgrades to get generating capacity to the load. A reliability-must-run (RMR) unit would have an infinite value.

Reliant commented that units used to resolve local constraints will be allowed to participate in the competitive power market at the prevailing price. Therefore, all units should have a market-based cost-benefit analysis applied to them for cost recovery. EGSI commented that the retrofit option should be considered for RMR units only if no other viable alternative exists.

Nucor and Calpine commented that the cost effectiveness analysis should not be biased in favor of retrofitting for RMR units. PURA §39.263 requires that cost recovery be permitted only for the least cost option. If necessary, a waiver of the May, 2003, compliance deadline could be sought from TNRCC.

Environmental Defense commented that the price of power from RMR units should be capped to protect electric customers from unreasonable costs. Public Citizen suggested that other options to RMR should be evaluated, including enhanced transmission capability, load reductions, and redevelopment. TIEC commented that it would be extremely difficult to quantify the customer benefits of maintenance of RMR units.

Texas ROSE urged that the clean up objectives of PURA not be compromised. Utilities should be required to study energy efficiency alternatives, to incorporate public participation into the utility's application process, and to evaluate comprehensive criteria. Applications for cost recovery should be reviewed under the statutory standards applicable to review of applications for certificates of convenience and necessity, PURA §37.056.

CEED commented that the retrofit versus retirement comparison should be undertaken after the utility has determined that it is reasonable to continue the operation to support system reliability.

In its reply, Nucor commented that there are many other methods to deal with reliability issues than simply retrofitting without regard to costs. One option that should be considered is the potential that if the utilities are unwilling to do what is necessary to retain the market benefits of RMR units, the utilities can sell them to others who will. This type of market solution would avoid a utility subsidy and enhance market competitiveness.

In its reply, Calpine disputed Texas ROSE's suggestion that the cost comparison be conducted using factors appropriate for review of applications for certificates of convenience and necessity. PURA clearly establishes a least cost standard for evaluating compliance alternatives.

Calpine also commented that the commission should avoid distorting the market with artificial reliability adders for RMR units. But if retirement is the least cost option for a RMR unit, then the proposed rule should recognize that retirement may be delayed if the utility seeks a waiver from the TNRCC. Calpine agreed with Nucor that ERCOT could compensate RMR units directly for any uneconomic improvements. These additional costs should not be included in the individual utility's stranded costs.

In reply comments, TIEC suggested that the commission explicitly factor the likely duration of a unit's RMR status into the cost-benefit analysis of a utility's environmental cleanup options. TXU's recommendation that the commission assign an explicit value to the social impact of inadequate reliability in the cost-benefit analysis would assign high reliability benefits to all of the existing generating units in the Dallas-Fort Worth area and should be rejected.

The commission believes that reliability concerns must be taken into account in determining whether a unit should be retrofitted or retired. In particular, RMR units should receive special consideration in the cost-effectiveness analysis because of the critical nature of these units in ensuring reliability. The social cost of retiring RMR units outweighs the economic cost of retrofitting them to maintain reliability. Therefore, the commission has revised the proposed rule to provide that retrofitting a unit that is required to remain active in order to maintain reliability shall be deemed the most cost-effective option for that unit in light of the social consequences of diminished reliability. The commission shall give great weight to the recommendation of the ERCOT ISO in determining whether a specific generating unit must remain active in order to maintain reliability.

*Issue 6:* *After the electric utility has shown that retrofitting a facility is more cost effective than retiring, is there a benchmark amount that can be used to determine whether the level of expenditures are reasonable and prudent? If a benchmark is* *appropriate, then should the benchmark be expressed in dollars per kilowatt, dollars per kilowatt-hour, dollars per ton of nitrogen oxide removed or some other measure? Industry data should be provided to substantiate the comments made about the proper level of benchmarks. Provisions will be made to handle proprietary information if a request is made in response to this question.*

In general, utilities remarked that the benchmarks included in the proposed rule were unrealistic. While some utilities supported the use of appropriate benchmarks, other utilities opposed use of benchmarks altogether due to the difficulty in establishing reasonable benchmark levels. Non-utilities suggested other options for limiting prudence reviews. Some non-utility commenters were opposed to any type of benchmark.

EGSI and Reliant commented that benchmarks should not be used because of the difficulty in developing reasonable and realistic benchmarks against which every unit can be measured. The proposed benchmarks in §25.261(f)(1)(A) are unrealistic and do not reflect current industry costs. To the extent these benchmarks are average costs developed for the February, 1999 joint report by TNRCC and the commission, they are unreliable because they are averages based on only initial cost estimates, they use generic reduction and cost factors, and they do not consider heat rate impacts or lost generating capacity.

CSW was receptive to the benchmarks proposed in the rule only so long as a utility has the ability to prove that higher costs are appropriate in its particular case. Where a utility's costs come in under the benchmark, the true-up proceeding should require merely a confirmation that costs came in under the appropriate benchmarked levels.

TXU commented that the commission should use a $/ton of pollutant removed for evaluating alternative strategies. For evaluating reasonableness of costs associated with selected strategies, the commission should use $/kW to establish a presumed-prudent benchmark. However, TXU disagrees with the $/kW values for installation of selective catalytic reduction technology (SCR) on gas-fired units in the proposed rule. TXU suggested that two SCR values are required—one for in-duct and one for separate reactor SCR systems. The value for in-duct SCR should be $40/kW and the value for separate reactor SCR should be $64/kW.

Environmental Defense commented that appropriate costs should be used for the initial retrofit/retirement analysis. The costs used should be a cap on ultimate recovery.

Nucor and OPC commented that the rule should not establish a benchmark amount that can be used to determine whether costs are reasonable and prudent. Reasonableness of costs should be addressed on a case-by-case basis. Nucor further commented that the word "prudent" does not appear in the statute and is inapplicable to cost review. TIEC also opposed any standard that would presume costs as reasonable. Each utility's expenditures should undergo after-the-fact review. Without such review and if the benchmarks are too lenient, the utility may have a reduced incentive to control costs. If the commission decides to use benchmarks, an evidentiary hearing should be called to establish those benchmarks.

Public Citizen commented that using benchmarks for retrofit costs assumes three factors: (1) that the cost of reducing emissions from all units in Texas is the same; (2) that reductions cannot be obtained for less; and (3) that the market costs are not driven upward by heightened demand. If benchmarks are used, they should be limited to controls on gas units and combustion controls on coal units.

Texas ROSE suggested that the rule should incorporate requirements for competitive bidding. The best way to evaluate reasonableness of costs is to compare bids. Competitive bidding should establish a ceiling for recovery of costs. The same principles in §25.171 of this title (repealed effective October 14, 1999) regarding solicitations for certificates for convenience and necessity for generation facilities should apply to environmental retrofits.

In its reply, Calpine commented that a dollar-per-ton of pollutant removed measure is appropriate for comparing control technologies. The comparative cost analysis should reflect a dollar per kilowatt measure. Calpine disagreed with TXU's proposed benchmarks because they were not substantiated. Calpine referred the commission to Reliant and CSW records that may include costs of retrofitting fossil units with pollution control devices. Where multiple vendors are available, competitive bids should be solicited. Any benchmark that is established should be rebuttable.

EGSI objected to suggestions by other parties that the rule incorporate requirements for competitive procurement of retrofit equipment and installation. If it is reasonable under the circumstances to use competitive bidding, the commission's traditional prudence standard will recognize and give effect to that fact.

Reliant replied that it does not oppose benchmarks coupled with an opportunity for the utility to rebut a proposed benchmark. However, the benchmarks in the proposed rule are unreasonably low. Reliant opposed cost caps because they are not rebuttable.

In its reply, TXU opposed cost caps noting that they contradict statutory provisions that allow a utility to recover costs incurred for environmental clean-up. Second, there is insufficient information available to develop a cost cap.

Nucor generally supported the concept of benchmarks, but noted that rebuttable benchmarks favor the utility. Nucor suggested imposing a presumption of imprudence for costs exceeding benchmarked levels.

Public Citizen in its reply provided emissions control estimates from EPA analyses.

In reply comments, TIEC suggested that if the commission decides to employ benchmarks, they should be established through a contested case proceeding, not this rulemaking.

In its comments, the TNRCC provided information regarding the costs of emissions control devices. The TNRCC has some information indicating that gas-fired combustion controls could cost roughly $4.5/kW plus indirect capital costs of 30%. Gas-fired boiler technologies achieving

80% reduction run less than $25/kW while catalytic reduction can be achieved at costs ranging from $25-$35/kW. Coal-fired combustion control technology appears to run about $10/kW, while cost-fired catalytic controls range from $50-$80/kW.

The commission has determined that use of benchmarks that are presumed reasonable and prudent may aid in streamlining expenditure-review proceedings. If the benchmarks are set relatively low, there is little risk that a utility will not undertake appropriate cost control measures. Further, because the benchmarks need to be set at relatively low levels, it is appropriate to allow a utility the opportunity to justify higher costs. Therefore, the commission has determined that benchmarks based upon TNRCC's cost information should be included in the rule. Expenditures at or under the established benchmarks will be presumed reasonable and prudent; a utility may seek recovery of expenditures that are larger than those established in the benchmarks but will have a burden of proof to demonstrate the reasonableness of those costs. The commission also agrees that recoverable costs should be capped at the estimated costs for the alternatives selected under subsection (e). This approach fosters certainty regarding the amount of stranded environmental clean-up costs and discourages utilities from low-balling costs associated with either the retirement or retrofit options.

*Issue 7:* *What alternative procedure can be included in this rule to reduce the reliance on after-the fact review of the reasonableness and prudence of costs, thereby providing customers and companies greater certainty of the costs to be recovered for air emissions reductions?*

Most commenters were opposed to use of benchmarks or cost caps. These commenters were in favor of an after-the-fact review of the reasonableness of a utility's expenditures in achieving required emissions reductions. Other commenters felt that cost caps provide an opportunity to minimize litigation about the reasonableness of expenditures.

Calpine suggested that the commission institute a cost cap and a rebuttable presumption that costs above a cap are imprudent. Such a cost cap would limit litigation and force utilities to bear the cost of their own overruns as competitors already have to do. Further, a cost cap and rebuttable presumption would create a strong incentive to control costs. Reliance on after-the-fact review could also be limited if utilities were required to select the least-cost alternative. This approach would reduce litigation about whether selection of a higher cost alternative was justified.

CSW suggested that, if benchmarks are used, costs below those benchmarks should be subject to only minimal scrutiny during the true-up.

Environmental Defense suggested that costs should be capped at levels used in the retirement/retrofit analysis. And Nucor recommended limiting recovery to the lesser of actual costs incurred or an estimated amount reviewed and approved by the commission at the time the utility's proposed plan is evaluated.

EGSI, Reliant, and TIEC felt that an after-the-fact review would be required. OPC opposed any procedure that would not allow an after-the-fact review of utility expenditures.

Texas ROSE commented that if cost overruns occur, a utility should be required to submit a revised cost-benefit analysis. If the analysis no longer supports the alternative selected, the utility should forfeit cost recovery. When costs are recovered, amounts should be certain, i.e., based on invoiced costs. Prior to recovery of costs, a utility should be required to document emission reductions. And the term of the cost recovery period should be limited, not to exceed the remaining useful life of the plant.

TXU suggested that review proceedings could be streamlined by establishing a standard approach to economic analysis so all parties can know how tests are to be performed. Review of emissions reduction plans should be expedited and more reasonable benchmarks established for SCR on gas-fired plants.

In their replies, Calpine and TIEC suggested that a prudence review should be required even if a utility's expenditures fall under the original estimate, cap, or benchmark.

In its reply, Reliant suggested that a utility be allowed to choose whether to have its emissions reduction plan reviewed before expenditures are made and have the reasonableness of expenditures addressed in true-up, or to or wait until true-up for review of both the emissions reduction plan and the reasonableness of expenditures. EGSI supported this recommendation. TXU indicated that a two-step proceeding that allows evaluation of a utility's plan prior to prudence review of expenditures is needed.

Nucor did not categorically oppose a two-step process, but argued that whatever process is used, there must be adequate time to review a utility's proposals. In addition, limiting recovery to the lesser of actual or estimated expenses would limit litigation.

The commission agrees with Calpine that some cap upon the utility retrofit costs is appropriate. Therefore, to promote some certainty with respect to costs for both utilities and ratepayers, the commission finds that it is appropriate to use the cost estimate submitted by the utility for the retrofit versus retirement cost-effectiveness test as the maximum amount, or cap, that will be deemed as prudent in the post-retrofit reasonableness evaluation. This will assure that the utility gives its best estimate of retrofit costs for the retrofit versus retirement test, and does not underestimate costs for the first test and seek recovery for higher costs later on. However, while the retrofit cost effectiveness test is a plant-specific test, the commission's overall goal is to assure that air emissions are reduced at a reasonable cost. Therefore, it is appropriate to aggregate all the utility's plant-specific retrofit estimates into a fleet-total cost, that will serve as the cap on retrofit costs for that utility's fleet as a whole. This will help to encourage the utility to allocate its environmental retrofit investments in ways that achieve the maximum emission reduction across all of its units, rather than binding it to narrow, plant-specific cost limits.

The commission has determined that application of benchmarks, as discussed more fully in response to comments on Issue 6, is the most effective method of streamlining the process of reviewing utility expenditures. Where a utility's costs fall at or below benchmarked levels, after-the-fact review will not be necessary except to confirm that costs are at or below the specified levels. Where a utility's costs exceed benchmarked levels, the utility may seek to justify its higher costs, necessitating a more involved after-the-fact review process. As discussed more fully in response to comments on Issue 2, the commission believes a two-step review process is necessary to afford reasonable certainty regarding the fate of specific plants in advance of the true-up proceeding.

*Issue 8:* *The commission recognizes that regulatory risk is limiting the installation of new power generation in greenfield and brownfield sites in non-attainment and transmission constrained areas, thereby reducing the market value of those plant sites. The commission has been working with the TNRCC and ERCOT to reduce these regulatory uncertainties and to increase the opportunities for the incumbent utility to sell sites for redevelopment that would otherwise be slated for retirement. The commission believes that these sales or redevelopments would reduce ECOM, reduce concentration in the generation sector, and increase power generation within the non-attainment and transmission constrained areas while complying with the TNRCC air quality standards. In subsection (e)(1)(I) of the proposed rule, the owners of the generating facilities in a non-attainment and transmission constrained area will estimate the market value of redeveloping each plant site that contains generating facilities where a retrofit would not qualify for stranded cost recovery. The goal of this provision is to determine the best option for these generating facilities from the perspective of electric customers: retrofit of the facility, retirement, or the redevelopment as a new power plant. This same subsection provides a set of criteria to estimate the market value of redeveloping plant sites in a non-attainment and transmission* *constrained area. Is using these criteria a reasonable approach? If not, please suggest changes that allow the commission to better assess the market value of redeveloping a plant site.*

TXU commented that the redevelopment analysis is already subsumed within the retirement analysis, and no special rule provisions are needed. In fact, the redevelopment analysis would be superfluous and a waste of resources, since at its best, the redevelopment option will merely mimic the purchased power component of the retirement analysis.

Reliant stated that PURA does not require a utility to sell, or attempt to sell, any facilities to establish the market value of those assets. Instead, PURA provides several different alternatives for valuing assets as the basis for determining stranded costs. Each method will provide an appropriate estimate of the salvage, or market value of "environmental retirement" assets, including possible alternative uses of these facility sites. Therefore, the potential "redevelopment" value of retired plant sites will be fully accounted for in the market valuations placed on assets prior to true-up.

EGSI disagreed with the entire redevelopment concept and urged the commission to strike it in its entirety.

Calpine recommended that the commission not limit the range of particular alternatives available to determine the least cost alternative for achieving compliance with PURA §39.264. Rather, the commission should adopt a comprehensive approach that considers all of the reasonable alternatives for achieving compliance. Under such an approach, setting criteria for valuing the alternatives would be reasonable. Each site would need to be evaluated on an individual basis given the site's specific characteristics, including environmental issues. Also, retirement without redevelopment as a generating facility, such as an industrial park, parking garage, or sporting arena, should be considered.

In addition to the commission's proposed criteria, Calpine recommended that the following assumptions be incorporated into the rule: (1) environmental liability would be borne by the seller; (2) the emission allowances for retired facilities would be made available for sale; (3) environmental compliance costs related to requirements promulgated by the date of filing should be included; and (4) existing sites would be marketed and sold or retired based on the alternative that yields the greatest salvage value.

Environmental Defense argued that this analysis should be performed before the retrofit/retirement decision is made. If there are unrealized benefits of an existing site that would accrue to a new facility but not the existing facility, for the purposes of analysis, they could be entered into the analysis as an increase to the costs of the existing plant.

TIEC agreed with the proposed criteria for determining the market value of redeveloping a plant site, with two exceptions. First, it is inappropriate to exclude the cost of transmission upgrades from the valuation analysis. Second, it is inappropriate to assume that all plant sites have sufficient access to natural gas pipeline capacity at competitive prices. Each redevelopment analysis should be conducted on a site-specific basis to determine whether it is appropriate to include such costs in the analysis.

In its reply comments, Calpine argued that redevelopment is clearly an alternative to retrofitting that should be considered in determining the most cost-effective alternative. In response to Reliant's comment that valuation of the site is redundant and unnecessary because any value will be captured in the true-up proceeding, Calpine noted that the cost-effectiveness determination will occur before the true-up proceeding. And in response to TIEC's assertion that it is inappropriate to exclude transmission costs from the redevelopment option, Calpine suggested that redevelopment should result in lower transmission costs because the addition of new, more efficient units in a non-attainment area will avoid the need for new transmission into the area.

In its reply, TIEC commented that site redevelopment is a legitimate option to reduce emissions from a specific plant site. If site redevelopment is not evaluated, then the analysis will be distorted in favor of the retrofit option. TIEC disagreed with proposals to consider other alternatives for achieving environmental compliance beyond the options in the proposed rule.

The commission has determined that evaluation of a redevelopment scenario is not necessary to achieve the objectives of PURA §39.263. The retirement analysis already captures the essential elements of the redevelopment scenario. The emphasis of the redevelopment option on maintaining reliability is addressed through provisions of the rule that deem retrofit to be the most cost-effective option for units that must remain active to ensure reliability. Therefore, provisions of the proposed rule requiring a redevelopment analysis have been deleted. The commission notes, however, that the amount of generating capacity required to replace a retired electric generating facility may be reduced if transmission upgrades allow greater import capability, or if energy efficiency or distributed generation alter the need for the generating facility. Subsection (e)(1)(H) has been revised accordingly.

*Miscellaneous*

Public Citizen commented that it is not appropriate to prop up the oldest and dirtiest plants with retrofits if it will be cost effective to retire them in the next 15 years. Additional retrofits will be required to meet requirements of regional haze rules beginning in 2008. Also, PM-2.5 and an eight-hour ozone standard will soon be in place. Additional acid rain reductions and water use reductions will be required soon. $CO_2$ reductions will also be required in the next few years. Utilities should be required to address all of these emerging requirements in their cost-effectiveness analyses.

Public Citizen also commented that mercury emissions increase with the use of lignite. $SO_2$ scrubbers can remove about 30% of the mercury, but mercury scrubbers can remove significantly larger amounts of mercury. Also, bottom ash placed in lined and unlined pits could be a source of mercury contamination of water resources. There is some evidence that mercury-contaminated water bodies are located near large power plants.

The SEED Coalition commented that available evidence clearly shows that global warming is occurring and that governmental institutions and commercial entities are beginning to take this problem seriously. The cost of acting now to address global warming is less than the cost of dealing with its consequences. It is likely that $CO_2$ reductions will be required in the future. The cost of $CO_2$ reductions should be factored into this rulemaking. SEED wants the commission to include some probability of the cost of $CO_2$ retrofit on power plants and to address the economics of the retirement evaluation in terms of retirement versus retrofit. The SEED Coalition also commented that it is very likely that a determination to regulate methylmercury will be made soon. Power plants are the largest producers of methylmercury emissions.

The Sierra Club commented that electric power plants in Texas are a major water user, probably the number one industrial water consumer in the state. With the continuing drought and global warming, water shortages are becoming more critical issues. The commission needs to consider how precise water use data can be obtained in order to assess whether this is a critical issue.

Texas Clean Water Action commented that the largest releases of mercury to the environment are from power plants. When making a decision whether to retrofit or retire a plant, all of the appropriate cost/risk analyses should be conducted. These include looking at the ultimate cost of health care and review of fuel sources as well as review of the economic costs of mercury contamination on recreational and commercial activities, especially fishing. One goal should be to convert fuels to gas or sustainable energy sources. Mercury is virtually unregulated at this point so it is difficult to state the probability that Texas power plants will be required to reduce mercury emissions.

Environmental Defense stated that power plants in central and east Texas are responsible for some of the visibility problems at Big Bend National Park. Haze regulations will require that this visibility problem be addressed in the next 25 years. Potential future regulations ought to be addressed in a risk analysis in the rule just as insurance companies do all the time for internal planning purposes.

Reliant commented that electric customers will not be responsible for retrofit costs associated with future regulations in an unregulated market. If environmental costs are overweighted in the cost-effectiveness analysis, electric customers may incur higher rates than necessary because costs of potential environmental regulations could drive the cost of retrofits up so high that retirement of plants with substantial book value is the most cost-effective option. Therefore, electric customers may have to pay book value for a plant when they otherwise would not have had to do so.

The commission agrees with comments suggesting that future environmental regulatory requirements may impact the life-cycle costs of a retrofitted facility and therefore should be factored into the present cost-effectiveness analysis. However, the commission also acknowledges that, at some point, the nature and extent of future environmental regulations becomes too speculative to provide a basis for their consideration in this rule. The commission therefore believes it appropriate to develop a methodology for factoring into the retrofit versus retirement cost-effectiveness analysis the likelihood that the generating facility owner will incur costs prior to 2011 to comply with air emissions regulations. Comments received regarding this issue were not particularly helpful in providing specific information on the nature of potential future regulations, the likelihood that they would come to pass, or costs of implementation if they did come to pass. Therefore, the commission plans a workshop for September 21, 2000, to develop the methodology that will be used to factor into retrofit costs the costs to comply with air emissions regulations not currently in effect but that will take effect prior to 2011. The commission expects this methodology to identify specific air emissions regulations that could require compliance investments through 2010, the most likely year that those investments should be made, and the probability that those regulations and investments will come to pass. These will be used in individual utility compliance plan dockets to develop a probability-adjusted, time discounted cost of each future air quality requirement likely before 2011.

The commission received late-filed comments from Texas ROSE recommending that the amount of any property tax exemption gained by a utility as a result of installation of pollution control equipment not be recoverable by the utility as stranded costs. The commission agrees. Incurred costs under the rule include indirect costs such as property taxes. To the extent that a utility gains a property tax exemption from installation of pollution control equipment, it will not have "incurred" a certain amount of property tax costs. No recovery will be allowed for tax costs not incurred. The commission also notes that the definition of retrofit cost incorporates a provision requiring that property taxes be adjusted to reflect the benefits of any pollution control exemption available to the utility due to installation of pollution control equipment.

*Specific Subsections of the Rule*

*Subsection (a)*

Calpine commented that the provisions of (a)(2) should be modified to reflect the general purpose of mitigating stranded costs. As proposed, subsection (a)(2) would exhibit a purpose of mitigating stranded costs only for the redevelopment alternative.

The commission agrees and has amended the rule as recommended by Calpine.

*Subsection (b)*

Nucor commented that the provisions of subsection (b) should be revised to clarify that cost recovery by utilities subject to the regulation is limited as described in subsection (c).

The commission disagrees. Subsection (b) merely identifies the entities to whom the rule applies. An entity subject to the rule must still demonstrate compliance with other applicable portions of the rule, including subsection (c), to obtain cost recovery. No change was made in response to this comment.

*Subsection (c)*

Reliant and TXU objected to the proposed use of historical purchased power costs in determining cost of replacement generating capacity in subsection (c)(2). Reliant commented that the cost of annual generating capacity should be determined using market-based pricing. Where market-based pricing is not suitable due to lack of transparency in the generation market, the cost of replacement generating capacity can be determined using a model of the wholesale generation market based on reasonable forecasts of supply and demand.

TXU commented that the proposed use of historical costs does not capture all of the value that will be reflected in purchased power prices in the competitive market. In a fully competitive market, the purchased power price will reflect both energy and capacity prices. The proposed rule, however, relies only on energy prices. TXU proposed an alternative formulation of the cost of replacement generating capacity that involved several key elements. First, market entry price would be predicted using: (1) the ECOM model market price worksheet for a combined cycle combustion turbine at 80% capacity factor, based on an assumed construction cost of $475/kW in 2002, escalated at approximately 2.0% per year thereafter; (2) operation and maintenance costs as specified in the ECOM model, escalated at 2.0% per year after 1996; and (3) the debt, equity, and tax figures specified in the ECOM model. Second, a price-versus-utilization curve would be prepared based on known price duration relationships in other markets. And finally, a defined utilization curve would be prepared for the unit for which the replacement power is to be obtained (the average capacity factor from the last three years for the unit that is assumed to be retired, which is decreased at a rate of 2.0% per year to account for presumed decreasing utilization of existing plants as time passes).

The commission agrees that the purchased power cost portion of the definition of replacement generating capacity should be revised to incorporate a more forward-looking pricing model. Insufficient dialogue occurred during the comment period to flesh out appropriate price projections. Therefore, the commission has deferred development of the specific parameters of price projections. Price projections will be developed in a workshop scheduled for September 11, 2000. Staff's proposed price projections will be posted on the commission's website on or before September 1, 2000, for review prior to the workshop. The definition of purchased power cost has been revised to refer to a commission-approved price projection.

TXU also commented that utilization for the unit for which replacement power is to be obtained should be defined as the average capacity factor from the last three years for the unit that is assumed to be retired, decreased at a rate of 2.0% per year to account for presumed decreasing utilization of existing plants as time passes.

The commission agrees and has included a derating standard in the definition of cost of replacement generating capacity.

Calpine recommended that the definition of "region" in subsection (c)(8) should be modified to conform to the designations in TNRCC's rules. Specifically, Calpine recommended changing the terms "East Region" to "East Texas Region" and "West Region" to "West Texas Region."

The commission agrees and has made the recommended changes.

Public Citizen objected to the inclusion of transportation expenses in subsection (c)(12), indicating that transportation expenses should not be recoverable expenses under the rule.

The commission disagrees. To the extent that the cost-effectiveness analysis determines that the most cost-effective alternative for a lignite-fired unit to achieve required emissions reductions is to convert to western coal, certain costs of making that conversion should be recoverable. No change was made in response to this comment.

TXU recommended adding definitions for the following terms: after-tax discount rate, cost of retrofitted unit, cost-effective, estimated capital cost of retrofit, estimated additional operation and maintenance cost of retrofit, operation and maintenance cost of unit, practicable, prudence, reasonable, retirement cost, and system-wide basis.

These definitions are appropriate in the context of specific models suggested by TXU for cost comparison purposes. To the extent that any of these terms are included in the new definition of retrofit cost, they are defined therein. The other terms suggested by TXU need not be defined in the rule.

*Subsection (d)*

Public Citizen commented that subsection (d)(1)(B) should require that cost recovery be limited to the least cost option based on competitive bids.

The commission disagrees as more fully discussed in response to comments received from Texas ROSE concerning subsection (d).

Calpine commented that the phrase "that meets the requirements of this section" in subsection (d)(1)(B) was ambiguous because there could be costs incurred to implement an emissions reduction plan that are not capital costs directly related to the implementation of the rule. Calpine suggested that subsection (d)(1)(B) be clarified by referring to costs incurred to improve air quality pursuant to a plan approved by the commission under subsection (e).

The commission agrees and has made the recommended change.

The Park Service recommended that the rule allow recovery of costs incurred to implement regional haze regulations promulgated by the United States EPA and contemplated under the Clean Air Act.

The commission disagrees. EPA's regional haze regulations, while coordinated with regulatory programs designed to achieve compliance with national ambient air quality standards, are not themselves designed to address compliance with national ambient air quality standards. The commission does not have the ability to expand cost recovery under the rule beyond the circumstances dictated by PURA §39.263, though cost recovery for certain expenditures made to meet opacity limits is authorized under PURA §39.264(e). No change was made in response to this comment.

Public Citizen recommended that subsection (d)(1)(E) be revised by deleting language that allows recovery of costs associated with transportation equipment. Texas ROSE commented that recovery of costs that are not associated with environmental compliance, such as transportation, should not be allowed.

For the reasons discussed in response to Public Citizen's comments regarding subsection (c)(12), the commission disagrees. Recovery for only limited transportation expenses is provided for in the rule. The commission believes this limited recovery is reasonable. No change was made in response to this comment.

Nucor also commented that the provisions of subsection (d)(1)(A) should be revised by deleting the word "prudent" as the statute does not establish prudence as a test for cost recovery.

The commission disagrees. The commission typically reviews prudence of capital expenditures when determining whether a utility should be allowed recovery of the expenditure through rates. While the cost of a specific item may be reasonable, the decision to utilize that item in light of all surrounding circumstances may not be prudent. No change was made in response to this comment.

Nucor commented that the provisions of subsection (d) fail to properly address the distinction between cost recovery for retrofits and cost recovery for facility retirement because subsection (d) speaks only in terms of expenditures made to improve air quality. PURA §39.263(d) specifically states that cost recovery for a retired facility shall be limited to the facility's net book value, including retirement costs and offsetting salvage value. Texas ROSE also commented that the rule should allow only for recovery of net book value of a retired facility through stranded costs.

The commission agrees that cost recovery for facility retirement is limited to net book value less offsetting salvage value. The rule has been clarified by including a specific reference to qualifying costs for facility retirement.

Nucor also commented that the proposed rule improperly extends the definition of qualifying costs to include engineering, procurement, and installation of pollution control or transportation equipment. Texas ROSE commented that only direct qualifying costs are eligible for recovery.

The commission believes that engineering, procurement, and installation of pollution control or transportation equipment costs associated with achieving air quality improvements through retrofitting an existing facility are costs that are eligible for capitalization. No change was made in response to this comment.

Texas ROSE commented that qualifying costs should be limited to costs for equipment procured through competitive bidding.

The commission disagrees. The procurement process used by the utility is a factor that can be addressed in assessing the prudence of the utility's expenditures. Therefore, no specific provision regarding competitive bids is needed. No change was made in response to this comment.

Calpine recommended a new subsection (d)(1)(F) to implement a cost cap on recovery of expenses incurred in retrofitting a facility.

For the reasons discussed in response to comments regarding Issue 7, the commission agrees and has revised the rule accordingly.

Calpine also recommended a new subsection (d)(1)(G) to ensure that cost recovery is allowed only for facilities that obtain a permit under PURA §39.264. PURA §39.263 allows cost recovery for expenditures made in furtherance of achievement of national ambient air quality standards, expenditures made to reduce emissions at unpermitted, grandfathered facilities, and expenditures made to address other requirements imposed by TNRCC. Some facilities for which expenditures will be made will already have permits.

The language proposed by Calpine would result in denying cost recovery for emissions reductions made at all but unpermitted, grandfathered facilities. No change was made in response to this comment.

TIEC commented that the rule should be revised to state that reasonable and prudent environmental cleanup costs are only eligible for recovery if the utility has actually expended the funds for the project. A commitment to expend such funds is insufficient to establish eligibility for recovery. Moreover, cleanup costs should only be eligible for recovery after the pollution control equipment is installed and operating to reduce emissions at the plant. These standards are consistent with traditional ratemaking criteria, which grant cost recovery only for known and measurable costs that are used and useful. In general, provisions allowing "incurred" costs to qualify for cost recovery are necessary because some utilities may not be able to install and pay for all required emissions control equipment within the deadlines set forth in PURA §39.263.

The commission interprets the language of PURA §39.263 to require only that costs be reasonably expected to be incurred in order to meet the statutory deadlines for "incurring" costs. The commission also agrees that a utility should not be allowed recovery for costs that are never actually incurred; in reviewing the "reasonableness" of qualifying costs under subsection (f)(1), the commission will consider whether expenditures in support of qualifying costs have been or will be made.

Calpine commented that subsection (d)(4) (now (d)(5)) should be revised to state that emissions reductions are allocated on the basis of reductions needed at each facility, not reductions realized at each facility.

The commission disagrees. Cost reductions at any facility must meet the eligibility criteria of (d)(1), which require that expenditures be made to achieve required emissions reductions. This requirement is not obviated where reductions are allocated between multiple facilities. Therefore, Calpine's suggested change is unnecessary. No change was made in response to this comment.

*Subsection (e)*

Public Citizen suggested that application filing dates should be staggered so all utilities do not file applications for approval of their emissions reduction plans at the same time.

The commission does not believe that staggered filing dates are necessary. First, the commission anticipates that only five utilities will make filings under this rule. Presently, the commission does not believe that all of these filings will be made within a compressed time period, especially given the fact that the rule allows a utility to forgo initial approval of its emissions reduction plan. No change was made in response to this comment.

EGSI recommended that the rule be amended to require that an application for approval of an emissions reduction plan be filed no later than one year after the effective date of the rule. Calpine recommended that the rule specify an emissions reduction plan application deadline of June 1, 2001. A June 1, 2001, application deadline should allow utilities adequate time to finalize their compliance plans and thus reduce the risk of non-recovery to utilities. Moreover, if the commission determines that retiring a facility represents the least cost alternative, then an earlier decision will facilitate the market's response to that opportunity. The commission should recognize that delay shifts risk to potential market entrants. Developers will make siting decisions for their existing turbines based on current available information. More complete information means less risk to the developer. An earlier application deadline will also facilitate the commission's and ISO's planning efforts. The sooner it is known whether grandfathered facilities will be retrofitted, the sooner the commission and ISO can finalize plans related to the transmission network. An earlier decision would be especially valuable for planning purposes in those areas, such as North Texas, that are expected to face significant transmission constraints in the short-term.

TXU recommended that subsection (e)(1) be revised to authorize each utility to file an application for approval of the utility's emissions reduction plan immediately after the effective date of the rule. The proceeding would result in a conclusive determination, via a final order, that the utility's specific plan for the utilization of specified emission reduction strategies is reasonable, prudent, and cost-effective. Steps necessary to implement the plan must begin immediately in order to meet the deadlines for cost recovery prescribed by the rule.

The commission generally disagrees with EGSI and Calpine. Affected utilities are aware of the time limitations on expenditures eligible for cost recovery. It is incumbent on each affected utility to make application for approval of an emissions reduction plan, if desired, in a timely manner. However, the commission recognizes the need for certainty in the marketplace regarding the fate of specific plants prior to 2004. Therefore, it is appropriate to require that any utility that plans to seek recovery of environmental clean-up costs file its application for a cost-effectiveness determination on or before January 10, 2003. In response to TXU's comment, the commission notes that a practical limitation on filing an application for approval of a cost-effectiveness determination may exist in that until conclusion of the workshops, price projections to be used in calculating the cost of replacement generating capacity and the methodology for addressing the cost of future environmental regulations will not be available. The commission intends to expedite approval of price projections and the methodology for addressing the cost of future environmental regulations in order to allow applications to be filed as soon as reasonably possible after the effective date of the rule.

Texas ROSE commented that this rule should establish a set of environmental standards to serve as a proxy for future environmental standards and a basis for developing a cost-effectiveness analysis of alternative strategies. The commission should consider future environmental standards in the cost benefit analysis because there are a number of standards that are likely to change between 2000 and 2003, even though cost recovery is allowed only for nitrogen oxides and sulfur dioxides.

The commission generally agrees as discussed more fully in response to miscellaneous comments.

Calpine also recommended that subsection (e)(1) be modified to require that the filed plan represent the least cost option for meeting the requirements of PURA §39.264. Currently, the proposed rule only requires that the plan be "cost-effective under this section." The rule as currently proposed implies that an alternative other than the least cost alternative may be selected. If the rule is intended to permit alternatives other than the least cost alternative to be selected, then the rule should be modified because it is inconsistent with the directives of the Legislature. Under PURA §39.263(c)(2), retrofitting costs are only recoverable to the extent that the retrofitting alternative represents the most cost-effective alternative. Calpine submits that most cost-effective is synonymous with least cost. Therefore, it is appropriate for the rule to require the least cost alternative to be selected. Even if the commission had the flexibility to allow recovery of costs not associated with the least cost alternative, sound public policy would support the commission limiting recovery to the costs associated with the least cost alternative.

The commission disagrees. Requiring adoption of the least cost alternative does not provide the latitude necessary to consider other factors such as the social costs of failure to maintain reliability and is not consistent with PURA §39.263(c)(2) which requires approval of the most cost-effective option. No change was made in response to this comment.

TXU commented that quick determination of the cost-effectiveness of proposed emissions reductions plans is needed to ensure that required emissions reductions are achieved and reliability is not threatened. Therefore, the commission should provide for immediate and expedited review of the prudence of each utility's proposed emissions reduction plan. The purpose of the proceeding would be to quickly resolve the question of whether the utility's selection of its overall compliance plan is prudent. Then the utility can take immediate action to implement the plan. At the time of the true-up, the only issue to be resolved would be whether costs incurred to implement the approved plan were prudent.

The commission generally agrees that review of a utility's proposed emissions reduction plan should proceed on an expedited schedule. Therefore, as discussed in the commission's response to Issue 2 above, a 180-day schedule has been established for review of proposed emissions reduction plans.

TXU also commented that review of a proposed emissions reduction plan should address two issues: (1) whether the plan is reasonable and prudent; and (2) whether the plan incorporates the most cost-effective alternatives. TXU commented that prudence should be determined according to established standards previously applied by the commission. TXU recommended that the rule include a definition of prudence.

The commission disagrees. The meaning of the term prudence has been established through prior commission decisions. There is therefore no need to include a definition of prudence in this rule.

TXU commented that reasonableness should be determined in reviewing proposed emissions reduction plans by considering whether the utility's compliance strategy will reduce emissions as required by TNRCC rules in a manner that will be practicable and cost-effective. A plan is practicable if it achieves the required emissions reductions on a system-wide basis and allows the utility flexibility in operating its units so that reliability can be maintained. A plan is cost-effective as a whole if it displays prudent balancing of practicability and minimization of implementation costs, where such costs are evaluated on the basis of the system-wide total cost of pollutants removed. Total costs per ton removed should include both capital costs of the retrofit and expected incremental operating and maintenance costs associated with implementing the retrofit strategy. To be cost-effective, a plan need not represent the absolutely lowest-cost-approach available; rather, the plan must embody prudent consideration of both practicability and cost-effectiveness.

The commission agrees that reliability, emissions reductions levels, and cost are all aspects of proposed emissions reductions plans that must be evaluated by the commission in determining whether a proposed plan represents the most cost-effective alternative. No change was made in response to this comment.

TXU provided a lengthy discussion of a cost-effectiveness determination system that it proposed should be adopted by the commission. First, retrofit alternatives for each of a utility's electric generating units should be identified on the basis of feasibility of implementation. If two alternatives are equally practicable, the alternative with the lowest total cost per ton of pollutant removed should be selected. Once a retrofit alternative has been selected for a unit, a three-step economic evaluation process should be used. First, it should be determined whether it is economically rational to modify the unit, *i.e.*, is retrofitting the unit more cost-effective than obtaining replacement generating capacity. There is no need to estimate costs of retirement if it is clear that the retrofit strategy is more cost-effective than obtaining replacement generating capacity.

If the retrofitted unit cost is less than purchased power cost, then it is clear that retrofitting the unit will be more cost-effective than retiring it and obtaining replacement generating capacity, since removal costs (less salvage) will only add to the overall retirement costs (which include the costs of obtaining replacement generating capacity). Accordingly, if the retrofitted unit cost is less than the purchased power cost, the analysis is complete and the retrofit selection has been shown to be justified. If the retrofitted unit cost is greater than the purchased power cost, the analysis should move to Step 2, which will add in the removal costs of the retirement option.

If the retrofit cost is less than the purchased power cost plus the cost to retire in 2003, then retrofitting the unit will be more cost-effective than retiring it. Accordingly, the analysis is complete and the retrofit selection has been shown to be justified. If the retrofit cost is more than the purchased power cost plus the cost to retire in 2003, then the retrofit is not justified, unless it is needed for reliability purposes. To determine whether the retrofit is justified on the basis of reliability needs, the analysis should include consideration of those needs (i.e., go to Step 3).

Step 3 would involve a determination of whether it is economically rational to retrofit the unit because of reliability needs. This step is used only if the analysis under Step 2 shows that retirement would be more cost-effective than retrofitting *and* the affected unit is shown to reasonably be needed to ensure reliable service. In such a situation, the retrofit may be economically justified because of the overriding reliability concern. This step requires the explicit consideration of the costs of inadequate assurance of reliability. Because such costs are social costs that are extraordinarily difficult to quantify, it would be reasonable to use a surrogate that is based upon the estimated costs to employ the next reasonably available alternative to ensure the delivery of power – i.e., increasing transmission system import capability.

The commission does not believe that the three-step process contemplated by TXU is necessary. The commission has determined that reliability concerns must be addressed first. If a unit is needed for reliability, further in-depth analysis of the retirement alternative becomes problematic because of the high social costs of plant closure. The first two steps of TXU's proposal are generally collapsed into a single step in the cost-effectiveness analysis of the proposed rule. The commission does not believe that it is necessary to bifurcate the cost-effectiveness analysis originally proposed. The commission agrees with TXU, however, that the rule should define the process by which the net present value of retrofit options should be calculated. Therefore, the commission has adopted a process very similar to the one proposed by TXU for determining the net present value of retrofitted unit cost.

Finally, TXU commented that subsection (e) of the proposed rule should also be revised to expressly note that the reasonably estimated costs of the commission-approved emissions reduction plan are to be included in the initial competition transition charge (CTC) to be established in the unbundling cost-of-service (UCOS) cases. This would be consistent with the commission's rate filing package instructions for the UCOS cases and with the legislature's directive in PURA §39.201(g) that the initial CTC be established based upon all reasonably forecasted stranded costs. Furthermore, it makes good policy sense to include the estimated costs, since actually incurred costs should not differ significantly from the estimated costs, and the prudence of pursuing the strategies that will lead to the incurrence of such costs will have already been approved through the expedited litigated proceeding.

The provisions of the proposed rule do not preclude recovery of all or a portion of estimated environmental clean-up costs in the UCOS cases. However, the final determination of recoverable environmental cleanup costs will be made in the true-up proceeding under subsection (f) of the proposed rule. Subsection (f) has been revised to clarify that the final determination of recoverable environmental cleanup costs will be made pursuant to the provisions of subsection (f).

Calpine commented that electric utilities and affiliated power generation companies should be required to report the expected remaining life of the facility to allow determination of the total costs of the retrofit option if the unit is retired before the end of the present value analysis period. For example, if the expected remaining useful life is ten years and the analysis period is 15 years, as proposed under the rule, then five years of replacement generating capacity would need to be included in the retrofit option in order to accurately compare the retirement alternative with the retrofit alternative.

The commission agrees and has made the requested change.

Public Citizen commented that subsection (e)(1)(B) should be revised to specify additional pollutants and to require reporting of water used by the utility.

As discussed above in response to the miscellaneous comments, the commission agrees in part. However, PURA §39.263 addresses improvement in air quality and does not address water used by the utility. No change was made in response to the comment regarding water use.

Public Citizen commented that subsection (e)(1)(E) should be revised to add a requirement that targeted energy efficiency or load management be considered as alternatives to retrofit.

The commission agrees in part. Energy efficiency and load management measures are small components of the replacement option but cannot alone replace an entire power plant. Energy efficiency and load management can complement other options for replacement generation, particularly at smaller plants. The commission has revised the rule to require consideration of the impact of energy efficiency and other load management measures, including distributed generation, may have on replacing generating capacity at smaller units.

EGSI commented that subsection (e)(1)(E)(i) should be revised to reflect the fact that under TNRCC rules, emissions cannot be traded between EGSI plants located in the same region because they are in different "areas" under the state implementation plan.

The commission agrees and has made the requested change.

Calpine commented that the first sentence of subparagraph (E) should be modified to require the disclosure of all the options considered. Currently, the proposed rule only requires the disclosure of "other possible options." Full disclosure of all other possible options considered will facilitate the commission's cost effectiveness determination. Furthermore, parties inevitably will seek to discover all the options considered. Therefore, it would be administratively efficient to require disclosure as part of the initial application, especially if the commission shortens the time for processing applications as also recommended by Calpine.

The commission agrees and has made the requested change.

Public Citizen commented that the cost of the anticipated emissions reductions should be compared with the cost of other reduction strategies.

The commission believes the comparative cost analysis does evaluate the costs of different emissions reduction strategies, particularly in light of the requirement that the costs of future environmental regulations be considered.

EGSI commented that subsection (e)(1)(F) should be revised to explicitly state that the net present value of both capital and operating costs associated with a particular control technology should be included in the analysis.

The commission agrees and has made the requested change.

Public Citizen, Reliant, Calpine, TIEC and Texas ROSE commented that the 15-year period required for a comparative cost analysis is inappropriate. The appropriate period of the analysis should be dictated by the useful economic life of the unit being considered for retrofitting.

The commission disagrees. Analysis over a 15-year period will provide a fair assessment of the alternative and is reasonable. If a facility is to be retired during the 15-year period, the utility must address the cost of replacement generating capacity during the period from facility retirement to the end of the 15-year analysis period. No changes were made in response to this comment.

Reliant commented that the discount rate used in the comparative cost analysis should be simplified. The distinction between the cost of capital and the discount rate is unnecessary when a discounted cash flow methodology is being used to evaluate incremental options. Accordingly, subsection (e)(1)(F) should use the respective company's marginal weighted average after-tax cost of capital.

TIEC also disagreed with proposed use of a utility's after-tax weighted cost of capital as the discount rate for all net present value analyses. This approach assumes conventional financing of environmental cleanup costs. It would be more appropriate to apply a case-specific discount rate that reflects the utility's proposed financing of such costs. For example, if a utility opts to securitize its cleanup costs, the cost of capital associated with the utility's securitization bonds should be used in the net present value analysis. Alternatively, a utility may be able to finance its pollution control investments using tax-exempt financing. In this case, it would also be inappropriate to use the utility's after-tax cost of capital in the net present value analysis. Therefore, the rule should require the application of a case-specific discount rate that reflects the utility's proposed financing of its environmental cleanup costs.

Public Citizen commented that utilities should be required to estimate the cost of financing retrofits in three ways: as a part of the financing package of other stranded costs; as part of their invested capital; and as a pollution control device financed under §383 of the Texas Clean Air Act.

The commission believes that the approach recommended by Public Citizen would overly complicate the cost-effectiveness analysis. However, the commission agrees that a utility's cost of debt for purposes of this rule should be adjusted to reflect any tax exemption benefits for which a particular option might qualify. Subsection (e)(1)(F) has been revised to require adjustment of debt costs to reflect tax exemption benefits.

Texas ROSE commented that the rule should affirmatively state that the issuance of a permit by TNRCC has no bearing on the cost benefit analysis, allowed costs under SB 7, or the prudence of the utility's decisions.

The commission concludes that this statement is unnecessary. Nothing in the rule implies that the granting of a permit has an effect on the economic analyses. Moreover, the rule does not imply that merely because a generation facility received a permit from the TNRCC means that all emissions reduction expenditures by the utility were prudent. No change was made in response to this comment.

Texas ROSE and Calpine commented in favor of a cost-benefit methodology that accounts for all anticipated changes in environmental standards.

The commission generally agrees as more fully discussed in its responses to the miscellaneous comments.

Calpine commented that paragraph (1), subparagraphs (F) and (G), should be modified to reflect a more comprehensive analysis of the various alternatives. Currently, subparagraphs (F) and (G) are premised on the generation redevelopment option being a primary alternative. Although generation redevelopment is clearly an alternative that should be given serious consideration, there are other retirement alternatives that should be given equal consideration. Accordingly, Calpine recommends that subparagraphs (F) and (G) be reorganized to reflect a more comprehensive analysis of the alternatives.

The commission generally disagrees. The redevelopment option has been eliminated from the rule because redevelopment economics are largely subsumed within the economics of facility retirement. In evaluating a proposed emissions reduction plan, issues such as the appropriate salvage value attributed to a facility will be addressed. No change was made in response to this comment.

Calpine commented that the comparative cost analysis should explicitly provide that the least cost alternative must be selected.

The commission disagrees as discussed more fully in response to Calpine's comments regarding subsection (e)(1). No change was made in response to this comment.

Calpine commented that the comparative cost analysis should be modified to require that the retrofit option include a calculation of the replacement generating capacity costs associated with any derating of the facility due to the addition of pollution control equipment.

The commission disagrees because any adverse impact on capacity from added control technology is expected to be minimal. No change was made in response to this comment.

Texas ROSE recommended that the provisions of subsection (e)(1)(G) relating to estimated costs of retrofit be amended to require verification of all amounts paid as of May 1, 2003.

The commission disagrees. This provision is intended to allow assessment of the cost-effectiveness of the retrofit option before any expenditures are made. No change was made in response to this comment.

Public Citizen commented that the retrofit analysis should include a requirement that at least three bids be solicited for equipment and installation.

The commission disagrees for the reasons discussed in its response to comments received from Public Citizen regarding subsection (d)(1)(B). No change was made in response to this comment.

Reliant disagreed with the proposed use of an average of the past experience for operating costs for future operating costs. Expected supply and demand conditions must be considered in evaluating the quantity and timing of a unit's future operating costs. TIEC suggested that an evidentiary proceeding be held to establish the appropriate inflation escalators to be used in subsection (e)(1)(G).

The commission agrees that operating costs should include appropriate escalators for operations and maintenance costs. The commission has revised the rule to include operations and maintenance cost escalators from the ECOM model.

Reliant commented that net book value should not be included in the determination of whether a unit should be retired. PURA §39.263(d) simply indicates that the net book value (including retirement costs and salvage value) of units retired for environmental reasons "shall be included in the . . . stranded cost determination." It does not suggest that the net book value is necessarily or appropriately included in making a retirement decision.

The commission agrees. If a facility is retired, net book value of the plant, less offsetting salvage value, will be included in the utility's stranded costs, representing a cost to electric customers. It is appropriate to consider this cost in the cost-effectiveness analysis. No change was made in response to this comment.

Calpine commented that the assumptions regarding the analysis of the retirement option should be modified to reflect a more comprehensive analysis of the retirement alternatives. For example, the environmental liability associated with an existing site may be substantial. Moreover, customers will bear that cost either through lower salvage values or through higher stranded costs. Given that customers will ultimately bear the environmental liability associated with a site, the comparative cost analysis can be simplified if the rule provides that the analysis shall assume that any environmental remediation costs shall be borne by the seller. Additionally, the analysis should assume that the facility will be shuttered if shuttering the facility results in a greater salvage value. Such an assumption is consistent with a least cost analysis and recognizes that the degree of environmental remediation will depend in part on the redevelopment use of the property. For example, if the facility is shuttered and the property remains undeveloped, it is possible, depending on what the toxicology risk assessment demonstrates, that no environmental remediation would be required. In contrast, if a site was redeveloped as a day care facility, then substantial remediation could be required. Texas ROSE commented that the resale value of a power plant should be included as a value that would offset retirement costs to the utility.

The commission agrees with Calpine and Texas ROSE that the market value of facilities and equipment under reasonable scenarios should be considered in determining retirement costs. The provisions of proposed subsection (e)(1)(H) provide that market value of the land be addressed in determining retirement costs. It is possible that land will have no market value. No change was made in response to these comments.

Calpine commented that the comparative cost analysis should also recognize that costs to customers may be avoided by the selection of certain alternatives. For example, if a site were redeveloped or additional capacity were added in the area, it is possible that the construction of transmission facilities could be avoided. Therefore, Calpine recommended that the comparative cost analysis require an estimate of the transmission savings associated with the retirement option and that those savings be reflected as a credit to the retirement option.

This comment is directed to avoided costs of redevelopment. Because the provisions of the rule addressing redevelopment have been deleted, this comment is considered moot. No change was made in response to this comment.

Calpine also commented that, if the commission declines to adopt its recommended modifications to the comparative cost analysis, then the commission should modify the redevelopment analysis to require the redevelopment analysis regardless of whether the retirement option is selected. Currently, the rule as proposed appears to require a redevelopment analysis only if the retirement option is determined to be the more cost-effective alternative. In other words, it is not clear that a redevelopment analysis is required if the utility or affiliated power generation company is proposing to retrofit a facility. The commission should clarify the rule to indicate the circumstances under which a redevelopment analysis is required.

The commission disagrees. As discussed in response to comments regarding Issue 8 above, redevelopment alternatives will be subsumed within the retirement option. Therefore, redevelopment alternatives will necessarily be involved in the initial comparison between retrofit and retirement. No change was made in response to this comment.

Public Citizen provided a lengthy list of inputs to be considered in the cost comparison including book value of the plant; date in service; original retirement date; current capacity; energy produced over the last five years; current emissions rates for nitrogen oxides, sulfur dioxide, particulate matter, mercury, and toxins; water use; and amount of fuels used.

The commission agrees in part. Most of the factors that Public Citizen recommends be considered are incorporated into the rule. For example, the rule requires consideration of plant book value, current capacity, and current emission rates. In considering salvage value, the rule requires consideration of the value of pollution credits, infrastructure, and estimated market value of the site. Two of the factors recommended for consideration by Public Citizen, such as water use rates and water use rates after retrofit, have no bearing on air emissions reductions. As discussed further in response to miscellaneous comments, the commission has insufficient information on which to base considerations of pollutants other than air emissions. Other factors that Public Citizens recommends be considered, such as original retirement date and environmental liability at the site, would overly complicate the cost-effectiveness analysis. No change was made in response to this comment.

Public Citizen commented that transmission upgrade costs for redeveloped sites must be excluded from the redevelopment analysis.

The comment is moot given that the redevelopment alternative has been deleted from the rule. No change was made in response to this comment.

Public Citizen commented that the redevelopment option should be clarified by explicitly stating that the utility or the purchaser shall bear the expense of any clean up of the facility.

The comment is moot given that the redevelopment alternative has been deleted from the rule. No change was made in response to this comment.

Texas ROSE commented that the rule needs to be more specific about the individual plants that may be appropriate candidates for redevelopment rather than retirement. A process should be outlined for defining how a company "makes a reasonable effort to facilitate" a sale. Texas

ROSE recommended that notice of a proposed facility sale be widely distributed. Public Citizen recommended that notice of a proposed sale be advertised for 90 days and bids be provided to the commission under seal. Texas ROSE and Public Citizen also recommended changing the date from April 30, 2003 to April 30, 2002 to allow sufficient time for a redevelopment plan or another alternate plan to be carried out prior to the January 2004 true up.

These comments are moot given that the redevelopment alternative has been deleted from the proposed rule. No change was made in response to these comments.

Reliant commented that the provisions of the rule dealing with redevelopment were unnecessary in light of Reliant's response to Issue 8.

The commission agrees and has deleted the redevelopment alternative analysis from the rule.

Public Citizen commented that notice should be provided through a bill insert alerting customers to the filing of an application for approval of an emissions reduction plan along with the estimated monthly cost and an explanation of how consumers might get more information. A meeting within each utility service area should be held in the evening to explain the proposed clean up plans. The plans should be available both on the companies' and commission's web site.

The commission disagrees. The requirement for publication of notice provides adequate notice of this proceeding to interested persons. No change was made in response to this comment.

In general response to comments suggesting alternative cost-effectiveness analysis methodologies, the commission notes that the compressed time period available for reviewing and implementing emissions reduction plan precludes application of overly complex methodologies, in particular those that rely on information and data that is not readily obtainable by the utilities or the commission.

*Subsection (f)*

The Park Service commented that the proposed rule should clarify whether the $80 per kilowatt price for emissions controls includes both sulfur dioxide and nitrogen oxide controls.

The commission agrees and has made the requested clarification. The benchmarks in the proposed rule were for nitrogen oxide controls only.

Public Citizen commented that rather than allowing utilities to use benchmarks, utilities should be required to obtain at least three bids for emissions control equipment for each unit. If the commission chooses to allow benchmarks to be used, they should be limited to gas unit controls and the combustion controls on coal units. Public Citizen questioned whether any coal plants should or will need to be retrofitted to make an 80% reduction since only the W.A. Parish plants are within a non-attainment area in Fort Bend County. These plants were listed as likely to retire in the commission's 1999 study on environmental clean up costs. Public Citizen also questioned whether any other coal plants in the east Texas area need SCRs.

The commission disagrees. First, the commission does not believe that it is necessary to obtain bids for emissions reduction equipment. Timing constraints faced by the utilities may make obtaining estimates problematic. The commission also believes that benchmarks are at reasonably accurate levels, further obviating the need for bids. Whether or not benchmarks are provided for catalytic reduction equipment is not determinative of the need for those controls in the context of a particular case. No change was made in response to these comments.

Reliant commented that the use of predetermined benchmarks for establishing prudence or reasonableness is inappropriate. The retrofit of an existing generating unit will require the commission to do a unit specific review to determine the reasonableness of the costs. There is no one-size-fits-all approach for determining the reasonableness of retrofit costs. Examples of the unit specific factors that must be considered by the commission in evaluating the reasonableness of the costs associated with a unit retrofit include baseline emission levels, degree of reduction required, and ease of construction access to install pollution control technology.

Calpine recommended that the commission create a presumption that costs in excess of the benchmarks established by the commission are imprudent. Calpine also recommended that the commission adopt a cost cap.

TXU commented that the rule should be revised to bifurcate and increase the levels specified for SCR on gas-fired plants. Of course, the maximum amount that could be recovered would be the actual incurred costs, even if those costs are less than the applicable presumed-prudent levels.

The commission disagrees with TXU and Reliant. TXU and Reliant failed to provide any documentation to substantiate their assertions that the benchmarks in the proposed rule are too low. The commission believes that the estimated control technology costs submitted by TNRCC, based on its own experience and review of available literature, are reasonable and conservative. Given that a presumption of reasonableness will apply to costs below the rule's benchmarks, it is important that the benchmark levels not be too liberal. Based on TNRCC's comments, the commission has established the following benchmarks: $7.00 per kilowatt for combustion controls on gas-fired electric generating facilities; $25.00 per kilowatt for controls that result in 80% reduction of nitrogen oxide emissions on gas-fired electric generating facilities; $10.00 per kilowatt for combustion controls on coal-filed electric generating facilities; and $50.00 per kilowatt for controls that result in 80% reduction of nitrogen oxide emissions on coal-fired electric generating facilities. As noted previously, the commission adopts Calpine's recommendation to set a cost cap for the prudence of utility environmental retrofit costs. This cap will be set at the utility's retrofit cost estimate used for its retrofit versus retirement cost-effectiveness test on a fleet-wide basis.

TXU commented that subsection (f) should be modified to recognize that utilities that have obtained commission pre-approval for their emission reduction plan will not be subject to second-guessing regarding the elements of that plan at the time of the true-up. Instead, the only issue to be litigated with respect to environmental costs in the true-up proceeding for those utilities would be whether they have prudently implemented the commission-approved plan. For utilities that have not obtained commission pre-approval, all issues under the rule would be subject to determination in the true-up (i.e., both a determination of whether the emission reduction strategy was reasonable, prudent, and cost-effective, and a determination of whether the utility was prudent in implementing that plan and incurring actual costs).

The commission agrees that utilities that should not be subject to second-guessing regarding the elements of the emissions reduction plan at the time of true-up. The only issue involved in the true-up proceeding is the prudence of expenditures to implement the emissions reduction plan. The rule has been amended to clarify the scope of review during the true-up. However, as previously noted, estimates regarding the emissions reduction plan will serve as a cap on cost recovery.

Reliant commented that subsection (f)(1)(B) is unnecessary because the redevelopment option will be addressed through the retirement option.

The commission agrees that with deletion of the redevelopment alternative, subsection (f)(1)(B) is superfluous. Therefore, subsection (f)(1)(B) has been deleted.

TIEC disagreed with the provisions of subsection (f)(2) that limit the scope of review in the true-up proceeding to capital costs incurred in implementing the commission-approved alternative. To be allowed recovery of environmental cleanup costs, a utility should bear the burden of proof to demonstrate that its pollution control expenditures were kept as low as reasonably possible for the approved alternative selected in its cost-effectiveness determination. Recovery of a utility's environmental cleanup costs for an approved pollution control alternative should in no event exceed the projected costs initially used to justify that alternative in the utility's cost-effectiveness determination proceeding. Therefore, the rule should be revised to clarify that parties are not precluded from using evidence from the cost-effectiveness determination proceedings to argue whether a utility's incurred environmental cleanup costs are eligible for recovery in the ECOM true-up proceeding.

The commission disagrees. The purpose for a two-step process is to allow the utility certainty in moving forward to achieve emissions reductions. To allow the initial approval of a utility's emissions reduction plan to be relitigated in the true-up proceeding would defeat the purpose of the initial proceeding. No change was made in response to this comment.

TIEC strongly supported the proposed rule's determination that environmental cleanup costs will only be eligible for stranded cost recovery during the ECOM true-up proceedings.

This rule does not prohibit recovery of estimated environmental cleanup costs through mechanisms other than the true-up. However, final approval of costs incurred pursuant to the rule is reserved for the true-up. Language to clarify that final cost approvals will be done through the true-up has been included in the rule.

Additional changes have been made to the rule to delete unnecessary verbiage.

This section is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2000) (PURA) which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction and specifically, §39.263, which allows a utility to recovery certain capital costs incurred to improve air quality in accordance with PURA §39.264 or to achieve compliance with national ambient air quality standards; and PURA §39.264, which authorizes the TNRCC to adopt rules to improve air quality.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 39.263 and 39.264.

**§25.261. Stranded Cost Recovery of Environmental Cleanup Costs.**

(a) **Purpose.** The purpose of this section is to:

(1) establish the procedures and criteria for determining the amount of stranded cost recovery electric utilities and affiliated power generation companies shall receive for environmental cleanup costs incurred to improve air quality in the state pursuant to Public Utility Regulatory Act (PURA) §39.263; and

(2) minimize stranded costs associated with the implementation of PURA §39.264.

(b) **Applicability.** This section applies to:

(1) electric utilities that seek to recover capital costs incurred during the period January 1, 1999 to April 30, 2003 to improve air quality; and

(2) affiliated power generation companies that seek to recover capital costs incurred during the period January 1, 2002, to April 30, 2003 to improve air quality.

(c) **Definitions.** The following words and terms, when used in this chapter, shall have the following meanings unless the context clearly indicates otherwise:

(1) **Conservation Commission —** The Texas Natural Resource Conservation Commission.

(2) **Cost of replacement generating capacity —** The cost of replacing generating capacity lost through retirement of an electric generating facility. The annual cost of replacement generating capacity will be calculated using the following equation:

| | |
|---|---|
| RGC=(PP)(G) | |
| Where: | |
| RGC = | Annual cost (in dollars) of replacement generating capacity |
| PP = | Purchased power price determined using commission-approved price projections. |
| G = | Amount of generation (megawatt-hour), which is the annual average of the output of the applicable electric generating facility for the three most current years as reported on Form EIA-767 or if not available on Form EIA-767, then the average annual output as reported to the commission, declining for the years 2004 and thereafter at the rate of 2.0% per year. |

(3) **Electric generating facility** — A facility that generates electric energy for compensation and that is owned or operated by a person in this state, including a municipal corporation, electric cooperative, or river authority.

(4) **Expected remaining life** — The estimated life in whole years of the generating facility from May 1, 2003 as estimated by the utility at the time of filing its application for approval of its cost-effectiveness determination plan.

(5) **Net book value** — The original cost of an asset less accumulated depreciation.

(6) **Offset —** The allocation of emission allowances or credits from one facility to another facility in the same region.

(7) **Operations and maintenance (O&M) escalator** — The applicable operations and maintenance (O&M) escalator set forth in the unbundling cost of service rate filing package. The O&M escalator for a gas-fired electric generating unit shall be 2.0% and the O&M escalator for a coal-fired electric generating unit shall be

1.0%. Notwithstanding the foregoing, the O&M escalator for TNP One shall be 1.5%.

(8) **Region —** The East Texas Region, West Texas Region, or El Paso Region, as defined by the conservation commission at 30 TAC §101.330.

(9) **Retirement —** The permanent removal from service of an electric generating facility.

(10) **Retrofit —** The installation of control technology on an electric generating facility to reduce the emissions of nitrogen oxide, sulfur dioxide, or both.

(11) **Retrofit Cost —** The net present value of the total capital cost and operating and maintenance cost to operate an electric generating facility after installation of a retrofit. The cost of a retrofitted unit shall be expressed in net present value dollars as of 2003 using the equation VALUE = (ECCR + O&M + FUEL + O&MR + OE), where:

(A) VALUE = net present value in 2003 over the expected remaining life of a retrofitted unit;

(B) ECCR = net present value of the estimated capital cost of retrofit as of 2003 and the net present value as of 2003 of the expected capital cost of environmental controls installed no later than 2010 to meet future regulations for emissions. The commission will adopt a methodology for calculating the capital cost of environmental controls to meet future regulations for emissions.

(C) O&M = net present value as of 2003 of operation and maintenance cost of unit without retrofit, calculated as O&M = (((average of plant non-fuel fixed O&M cost reported for the most current five calendar years on FERC Form 1) x ((maximum generator nameplate rating as reported for the unit on Form EIA-411 or if not available on Form EIA-411, then the rating as reported to the commission) / (sum of the maximum generator nameplate rating as reported for all units comprising the plant at which such unit is located on Form EIA-411 or if not available on Form EIA-411, then the rating as reported to the commission))) + ((average of plant non-fuel variable O&M cost, expressed in $/MWh, reported for the most current five calendar years on FERC Form 1) x (unit generation for 2003, calculated as the average generation in MWh for the most current five years as reported on Form EIA-767 or if not available on Form EIA-767, then the generation as reported to the commission, declining for the years 2004 and thereafter at the rate of 2.0% per year)) escalated by the O&M Escalator for each year subsequent to the year in which the cost effectiveness determination was filed;

(D) FUEL = Cost of fuel, calculated as net present value as of 2003, over the expected remaining life of the retrofitted unit, using the equation FUEL = HR x G x Gas where:

(i) HR = unit heat rate, calculated as the average of the heat rate reported for the most current five calendar years on Form EIA-411 or if not available on Form EIA-411, then the heat rate as reported to the commission, expressed in mmBtu/MWh;

(ii) G = unit generation, calculated for 2003 as the average generation in MWh reported for the three most current calendar years on Form EIA-767 or if not available on Form EIA-767, then the generation as reported to the commission, declining for the years 2004 and thereafter at the rate of 2.0% per year; and

(iii) Gas = forward natural gas prices as adopted for the ECOM model in August, 2000 by the commission;

(E) O&MR = Net present value as of 2003 of estimated additional operating and maintenance cost resulting from the retrofit, beginning with costs for calendar year 2003 and escalated each year at 2.0% per year and the net present value as of 2003 of the expected operating and maintenance cost of environmental controls to meet future regulations for emissions beginning with costs for the estimated year of installation and escalated each year through 2010 at 2.0% per year. The commission will adopt a methodology for calculating the O&MR cost of environmental controls to meet future regulations for emissions;

(F) OE = Ownership effect, calculated as the net present value as of 2003, over the expected remaining life of the retrofitted unit, using the equation OE = VALUE(PT + PI + CAPIMP – OMTA – CAPIMPDEP – DEPTAXBEN) where:

(i) PT = annual property tax, adjusted for income tax benefit = (applicable property tax rate) x (ADJECCR) x (1 – income tax rate) where ADJECCR is equal to ECCR reduced to reflect any property tax exemption for which the unit might qualify;

(ii) PI = annual property insurance, adjusted for income tax benefit = (applicable property insurance rate) x (ECCR) x (1 – income tax rate);

(iii) CAPIMP = annual continuing capital improvements, adjusted for income tax benefit = (1.25% of the sum of the net book value plus improvements) x (1- income tax rate);

(iv) OMTA = annual income tax benefit on O&MR= (income tax rate) x (estimated additional operating and maintenance cost of the retrofit for the applicable year);

(v) CAPIMPDEP = annual tax depreciation on CAPIMP; and

(vi) DEPTAXBEN = (income tax rate) x (annual tax depreciation on ECCR).

(12) **Transportation equipment** — A rail spur at a lignite-fired electric generating facility installed to receive deliveries of western coal. Transportation equipment does not include rail cars and unloading facilities.

(d) **Requirements.**

(1) **Qualifying retrofit costs.** To be eligible for recovery as invested capital pursuant to PURA §39.263, a retrofit cost must be:

(A) reasonable and prudent;

(B) incurred in carrying out the most cost-effective alternative for improving air quality as approved pursuant to this section;

(C) incurred to reduce or offset emissions by an amount and at a location that is consistent with the air quality goals and policies of the conservation commission;

(D) incurred to offset or reduce the emission of airborne contaminants from an electric generating facility, where:

(i) the emission reduction or offset is determined by the conservation commission to be an essential component in achieving compliance with a national ambient air quality standard. For purposes of this section, any emission reduction or offset achieved by an electric utility or affiliated power generation company to comply with conservation commission regulations at 30 TAC Chapter 117 is deemed to have been determined by the conservation commission to be an essential component in achieving compliance with a national ambient air quality standard; or

(ii) the reduction or offset is necessary for an unpermitted electric generating facility to obtain a permit in the manner provided by PURA §39.264; and

(E) associated with the engineering, procurement, or installation of pollution control equipment or transportation equipment, or the purchase of emissions allowances.

(2) **Qualifying retirement costs.** Retirement costs may be included in the electric generating facility's stranded cost determination if retirement of the facility is the most cost-effective alternative, taking into account the cost of replacement generating capacity. Recoverable retirement costs are the net book value of the facility, including retirement costs, less salvage value.

(3) **When costs incurred.** For purposes of this section, the electric utility or affiliated power generation company has incurred costs if it has expended funds or has committed to expend funds under the terms of a written agreement.

(4) **Operating and maintenance costs.** This section does not authorize the recovery of operating and maintenance costs or the capital cost of a new electric generating facility.

(5) **Apportionment of reductions.** As provided in this paragraph, the commission may apportion the capital invested to reduce emissions of nitrogen oxides, sulfur dioxide, or both, among one or more entities owning facilities located in the same region. The capital investments for which recovery is sought must have been incurred pursuant to a written agreement between the entities executed prior to the date any such costs were incurred. The commission may not apportion capital costs under this provision unless the criteria of paragraph (1) of this subsection are met for each electric generating facility seeking capital cost recovery. Capital costs shall be apportioned by prorating the total capital invested between entities on the basis of reductions of nitrogen oxides, sulfur dioxide, or both, realized at each participating entity's facilities in the region.

(e) **Request for approval of cost-effectiveness determination.**

(1) **Application.** On or before January 10, 2003, an electric utility or affiliated power generation company that seeks recovery of capital costs pursuant to this section shall file an application for a determination that its plan for meeting the requirements of PURA §39.264 and the regulatory programs designed to achieve compliance with national ambient air quality standards are cost-effective under this section. No more than one application may be filed for generating facilities owned by the same electric utility or affiliated power generation company in the same region. The application shall include the information specified in subparagraphs (A) – (H) of this paragraph.

(A) **Description.** A general description of the generating facility, including but not limited to:

(i) net generating capacity in megawatts;

(ii) type of fuel used for electric generation;

(iii) the county and region in which each facility addressed in the application is located;

(iv) average capacity factor for the three most current calendar years as reported to the commission;

(v) generation in megawatt-hours for the three most current calendar years, as reported on Form EIA-767 or if not available on Form EIA-767, then as reported to the Public Utility Commission of Texas;

(vi) the expected remaining life of the facility; and

(vii) any other information required to perform the analysis prescribed by this section.

(B) **Total emissions**. The total annual emissions (in tons) of nitrogen oxides and sulfur dioxide:

(i) for the year 1997;

(ii) for the most recent calendar year for which data is available;

(iii) that is expected for the first calendar year after the implementation of the air quality improvement strategies for which cost recovery will be requested; and

(iv) for the calendar years 2003 through 2005.

(C) **Allocated emissions allowances.** The number of emission allowances allocated to the electric generating facility by the conservation commission.

(D) **Capital cost estimate**. The total amount of qualifying capital costs for each option evaluated by the electric utility or affiliated power generation company.

(E) **Alternatives.** A decision analysis for all electric generating facilities owned by a utility or affiliated power generation company in the same region comparing the cost-effectiveness of the retirement option with retrofit options and all other possible options considered by the electric utility or affiliated power company. Other options shall include:

(i) offsetting emissions at the electric generating facility by installing control technology at another facility, consistent with the rules of the conservation commission; and

(ii) switching fuel used for electricity generation at the electric generating facility.

(F) **Comparative cost analysis.** The net present value of the capital, operating, and maintenance costs of each option considered pursuant to subparagraph (E) of this paragraph. The period of the analysis shall begin on May 1, 2003, and extend for a period of 15 years. The discount rate used in the analysis and the cost of capital associated with each option shall be calculated differently. Both shall start with the capital structure and cost of capital as they are reported for the end of 1999 in the utility's annual report made pursuant to PURA §39.257. The discount rate shall be the after-tax weighted cost of capital, while the cost of capital associated with each option shall be taken directly from the annual report, except for the cost of debt. The cost of debt for this purpose shall be the average cost of debt for the months of October, November, and December 1999 as reported by Moody's Investors Service for utilities with the same Moody's bond rating as the utility making the filing adjusted to reflect any tax-exemption benefits for which a particular option might qualify. All assumptions used in the analysis shall be provided. If the lowest-cost alternative is not selected as the most cost-effective, an explanation of why it was not selected shall be provided. Where an electric generating facility is required to remain active to ensure reliability, retrofit shall be deemed to be the most cost-effective alternative for that facility. The commission shall give great weight to the recommendation of the Electric Reliability Council of Texas (ERCOT) Independent System Operator (ISO) in determining whether a facility is needed for reliability purposes.

(G) **Retrofit.** The retrofit alternative analysis shall include calculation of retrofit cost and an estimate of the total cost per ton of pollutant reduced for each option considered. The retrofit alternative analysis shall also include the time-discounted, probability–adjusted cost of environmental retrofits that are reasonably foreseeable to require air quality improvement compliance no later than 2010. If the expected remaining life of the generating facility is less than 15 years, the retrofit analysis shall include the net present value of all relevant costs of retirement for those years remaining after the retirement date.

(H) **Retirement.** The retirement analysis shall include the net present value of all relevant costs of retirement for each electric generating facility, including:

(i) the cost of replacement generating capacity in dollars as defined in subsection (c)(2) of this section. The amount of replacement generating capacity shall be the generating capacity of the unit retired adjusted, when appropriate and depending upon the size of the unit, to reflect energy savings or additions attributable to energy efficiency, transmission upgrades, distributed generation, and other similar measures; and

(ii) the net book value of the facility, including retirement costs and offsetting salvage value, which includes but is not limited to the market value of the land after the facility is retired, and the value of water rights, pollution credits or benefits associated with the facility, and other infrastructure.

(2) **Notice.** Notice of an application for approval of a cost-effectiveness determination shall be provided through newspaper publication once a week for two consecutive weeks in a newspaper of general circulation throughout the service area of each electric generating facility addressed in the application. Such newspaper notice shall state in plain language:

(A) the purpose of the application;

(B) the electric generating facilities addressed in the application;

(C) the air quality improvement strategy proposed for each electric generating facility addressed in the application; and

(D) the date the application will be deemed approved if no objection is filed with the commission.

(3) **Approval of an application for determination of cost-effectiveness.** An application shall be deemed approved without further commission action if no objection to the application is filed with the commission within 60 days after the application was filed and adequate notice has been completed.

(4) **Decision.** If an application for approval of an emissions reduction plan is not approved under paragraph (3) of this subsection, the commission shall render a decision approving or denying the application within 180 days from the date of filing of a complete application unless good cause is shown for extending the 180-day period.

(f) **Reconciliation of environmental cleanup costs during the true-up proceedings.** The commission's final determination of recoverable environmental cleanup costs under PURA §39.263 shall be made during the true-up proceedings under PURA §39.262, subject to the provisions of this paragraph:

(1) **Burden of proof for recovery of costs.**

(A) **Burden of proof.** In determining the amount of environmental cleanup costs that the electric utility may recover as invested capital under PURA §39.263, the electric utility or affiliated power generation company has the burden of showing that its qualifying costs during the period were prudent, reasonable, and necessary and were incurred to implement the most cost-effective alternative.

(B) **Benchmarks.** For those electric generating facilities where their owners can show that retrofitting the facilities is more cost effective than retiring them, the commission presumes that costs for retrofitting a natural gas-fired electric generating facility that are no more than $7.00 per kilowatt for nitrogen oxide combustion control technology and $25 per kilowatt for technology that reduces nitrogen oxide emissions by 80% or more are reasonable and prudent. Likewise, the commission presumes that costs for retrofitting a coal-fired electric generating facility that are no more than $10 per kilowatt for nitrogen oxide combustion control technology and $50 per kilowatt for technology that reduces nitrogen oxide emissions by 80% or more are reasonable and prudent. For actual costs that exceed these per-kilowatt benchmarks, the utility must establish that those costs were reasonably incurred. Costs that the utility estimates and the commission affirms as the estimated costs of each plant's environmental retrofit, as determined in a proceeding under subsection (e) of this section, shall be aggregated as the maximum reasonable and prudent investment for the fleet retrofit, and the costs in excess of the fleet total are not recoverable through stranded costs.

(2) **Scope.** Any issue related to determining the prudence and reasonableness of the environmental clean-up costs which the electric utility or affiliated power generation company is seeking recovery as invested capital shall be within the scope of the proceeding. The prudence and reasonableness of the alternative selected for each electric generating facility is not within the scope of this proceeding.

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 §25.261 relating to Recovery of Environmental Cleanup Costs is hereby adopted with changes to the text as proposed.

**ISSUED IN AUSTIN, TEXAS ON THE 7th DAY OF SEPTEMBER 2000.**

**PUBLIC UTILITY COMMISSION OF TEXAS**

**Chairman Pat Wood, III**

**Commissioner Judy Walsh**

**Commissioner Brett A. Perlman**