PROJECT NO. 23571

RULEMAKING CONCERNING	**§**	**PUBLIC UTILITY COMMISSION**
TRUE-UP PROCEEDING UNDER	**§**	
PURA §39.262	**§**	**OF TEXAS**

ORDER ADOPTING NEW §25.263, TRUE-UP PROCEEDING, AS APPROVED AT THE NOVEMBER 20, 2001 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts new §25.263, relating to True-Up Proceeding, with changes to the text published in the June 15, 2001 *Texas Register* (26 TexReg 4359). This new rule implements the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated (Vernon 1998, Supplement 2001) §39.252, which addresses a utility's right to recover stranded costs, and PURA §39.262, which requires the commission to conduct a true-up proceeding for each investor-owned electric utility after the introduction of customer choice and which prohibits over-recovery of stranded costs. Project Number 23571 is assigned to this proceeding.

The commission received written comments and/or reply comments on the proposed new section from American Electric Power Company (AEP); TXU Electric Company (TXU); Reliant Energy, Incorporated (Reliant); Texas Industrial Energy Consumers (TIEC); the Alliance for Retail Markets (ARM); Entergy Gulf States, Incorporated (Entergy); El Paso Electric Company (EPE); Texas-New Mexico Power Company (TNMP); the Steering Committee of Cities Serviced by TXU Electric Company and the Steering Committee of Cities served by Central Power and Light Company (Cities); and Office of Public Utility Counsel (OPC).

A public hearing on this rule was held at the commission's offices on July 25, 2001. To the extent parties offered oral comments at the hearing that differed from the submitted written comments, such comments are summarized herein.

Comments on specific questions posed in the rulemaking proceeding

The commission requested specific comment with regard to three questions related to the development of the final rule. The parties' responses to those questions are summarized below.

Preamble Question #1: The true-up adjustment required by PURA §39.262(d)(2) is determined in the proposed rule by calculating the effect on ECOM of using capacity auction prices, actual fuel costs, and actual sales as certain inputs to the ECOM model. Are there any substantive differences between using this method versus a method in which the adjustment is simply the difference between the price of power obtained through the capacity auctions and the corresponding power cost projections used in the ECOM model in the PURA §39.201 proceeding? If so, should an alternative method for calculating the adjustment required by PURA §39.262(d)(2) be incorporated into the final rule?

TXU commented that substantive differences exist between the method used in the proposed rule versus a method in which the adjustment is the difference between the price of power obtained through the capacity auctions and the corresponding power cost projections used in the excess-costs-over-market (ECOM) model in the PURA §39.201 proceeding. As one example, TXU noted that capacity auction prices could be driven by different underlying fuel costs than those used in the market price of the ECOM model.

ARM commented that the method proposed in the rule appropriately substitutes the actual capacity auction prices for the estimated "market price" in the ECOM model. ARM stated, however, that the proposed method adjusts the fuel cost and generation mix inputs to the ECOM model, and these adjustments would need to be examined in another contested case. ARM argued that PURA §39.262(d)(2) requires only that the capacity auction prices be substituted for the power cost projections originally employed in the ECOM model and that no other adjustments are contemplated or permitted. ARM urged the commission to avoid further adjustments to the ECOM model.

Cities contended that it is impossible to undertake a simple comparison between the power cost projections of the ECOM model and the general price of power obtained through the capacity auction. Cities commented that the price of each of the capacity auction components (baseload, intermediate, cyclic, and peaking) is not comparable to the ECOM model market price (stated separately for three different rate classes) because the load shapes do not match. Cities did not offer an alternative method.

TIEC stated that a simple comparison of market prices does not capture the effect on ECOM because the ECOM model calculates the net present value of a stream of lost revenues. The rerun of the ECOM model will result in an updated net present value that will reflect the change in cost of fuel less the change in market revenues. The true-up adjustment proposed in the rule is necessary, rather than the alternative proposed in this question.

Reliant commented that the two methods are not substantially different as long as the general method outlined in the proposed rule is performed correctly. However, Reliant stated that if the commission wishes to retain the ECOM model for purposes of the PURA §39.262(d)(2) true-up, that model will work appropriately only if power prices used as inputs to the ECOM model are disaggregated by generation type. If the ECOM model is used in the capacity auction true-up, Reliant provided two methods to accomplish such a disaggregation. Reliant pointed out that, historically, an estimated annual average power price has been used in the ECOM model because the specific market information by fuel type was not available. Reliant commented that now, however, the capacity auctions will yield actual power prices by generation type, and those actual power prices should be used in the ECOM model. Reliant further commented that, for purposes of the capacity auction true-up, the ECOM model has two main components: the price of power and the price of fuel. The difference between those components is the margin predicted to be available to contribute to fixed costs and therefore to reduce stranded costs. Reliant provided numerical examples illustrating that if actual fuel costs and sales amounts are not used, the contribution of a company's capacity auction results to stranded costs could be over- or understated.

Both Reliant and AEP commented that the "Plant Economics" feature of the ECOM model distorts the results of the capacity auction true-up because it allows the model to disallow costs that are truly economic. Under the assumptions of the ECOM model, the plant owner should not run a class of plants when they are not profitable; hence the ECOM model excludes those variable costs from stranded costs. In the proposed rule, an annual average price of power is calculated by dividing total revenues from the capacity auction by total megawatt-hour (MWh) sales from the capacity auctions, and then the "Plant Economics" worksheet in the ECOM model compares this average capacity auction price to the variable costs of each plant type (gas, nuclear, and coal/lignite) to determine whether the plant type is economic. Reliant commented, however, that in reality the decision whether to run a plant will be made based on the revenues that a specific plant will receive when it runs, not the average price for all generation plant types across a whole year.

Reliant argued, therefore, that the simplest method is to discard the ECOM model altogether and adopt a formula that preserves the net margin that exists in the ECOM model. Reliant commented that the purpose of the PURA §39.262(d)(2) true-up is to ensure that the affiliated power generation company (APGC) ultimately receives the same margin from the capacity auction process as the ECOM model predicted. The APGC may recover part of, all of, or more than that ECOM margin through the bid premiums. In addition, the APGC will experience some gain or loss on fuel when the capacity auction strike prices are compared to the APGC's actual costs. The remainder (or overcollection) of the margin should be recovered from (or paid back to) ratepayers in the true-up proceeding. Thus, Reliant submitted that at the time of the true-up the APGC can be made whole by the following formula that eliminates the need to re-run the ECOM model:

(ECOM market revenues – ECOM fuel costs) – ((capacity auction price x total busbar sales) – actual fuel costs)

AEP agreed, in general, with the overall direction in the proposed rule to true-up actual capacity auction and fuel prices to the ECOM model. However, AEP suggested there were two necessary adjustments to properly account for the fundamental differences between the ECOM model and the capacity auction products. These adjustments include: (1) the use of product specific market prices rather than average market prices; and (2) if average market prices are used, an adjustment to the economic "backdown" logic (i.e., the "Plant Economics" adjustment) utilized in the ECOM model, such that incremental costs to serve the capacity auction did not themselves become stranded. AEP believes it is more appropriate to account for these adjustments outside of the ECOM model as opposed to including them directly in the ECOM model, but admitted they could be adapted for use in the ECOM model if necessary. AEP stated that the use of either a weighted-average market price or product-specific market price will result in an accurate measure of ECOM if, and only if, the ECOM true-up occurs outside the ECOM model. Also, a necessary adjustment to the proposed rule methodology would be to adjust the capacity auction results for "product adjustments" that reflect the firm characteristic of the capacity auction products.

Like Reliant, AEP argued that the true-up calculation would be much more complicated if it were attempted within the ECOM model because of the use of the "Plant Economics" adjustment. AEP said there is a problem with using a per-megawatt weighted-average price as an input in the model as proposed in the rule because baseload prices will be weighted along with gas-fired products. The resulting weighted-average market prices will likely be substantially lower than the market prices that gas-fired generation will see in a deregulated market. If the commission uses the ECOM model to calculate the true-up amounts, to correct for the "Plant Economics" adjustment, the specific market prices by fuel type would need to be used instead of the proposed weighted-average price. Because of the problems involved with using the ECOM model for the capacity auction true-up, AEP submitted a formula similar to that proposed by Reliant to calculate the capacity auction true-up without the use of the ECOM model.

In response to Cities' contention that a simple comparison is not possible between the power cost projection of the ECOM model and the general price of power obtained through the capacity auction, TXU claimed that PURA §39.262(d)(2) requires that this comparison be made. TXU also disagreed with arguments by ARM and OPC that only capacity auction prices, and not fuel price and generation figures, should be updated in determining the amount of the capacity auction true-up. TXU noted that determining fuel price and generation updates would be a fairly minor undertaking and that all proceedings under Chapter 39 must be contested case proceedings unless otherwise noted. TXU further noted that if the power price in the capacity auction differs from the prices used in the ECOM model only because of fuel price changes, the commission would be making an apples-to-oranges comparison if it adopts ARM's proposal. TXU argued that adjusting fuel costs and generation to reflect changes in underlying circumstances is consistent with the methodology employed by the commission when it updated natural gas prices and power costs in the unbundled cost of service (UCOS) cases.

TXU also recommended that the commission not adopt the changes to subsection (i)(2) proposed by ARM that would calculate the capacity auction true-up amount based on the prices determined by a rerun of the ECOM model, multiplied by the total capacity auction sales for "that year" and divided by the originally projected sales for "that year." TXU complained that the reference to "that year" is confusing because the ECOM model produces a single present value figure, not different figures for each year. Further, TXU argued that the reason for computing the ratio of the capacity auction sales to predicted sales for the entire fleet is not clear.

Cities, in response to both Reliant's and AEP's proposal to true-up the amount of stranded costs for the years 2002 and 2003 by either abandoning or revising the ECOM model, stated that rather than modifying the model, Reliant and AEP are proposing to circumvent Senate Bill 7 by re-litigating issues already resolved by the commission. According to Cities, a true-up must be faithful to the ECOM model approved in the unbundled cost of service cases.

ARM argued in its reply comments that no adjustments to the ECOM model are permitted by the statute, "other than the substitution of prices based on the capacity auctions for the proxy 'market' price in the competitive scenario of the ECOM model." ARM commented that adjustments to the ECOM model that are advocated by the utilities in their comments "would constitute impermissible manipulation of the model to increase stranded costs" and would be illegal because PURA §39.262(d)(2) does not permit any adjustments to the ECOM model other than substitution of capacity auctions prices for the market prices in the model.

AEP replied that some of the commenting parties implied that PURA requires use of the ECOM model. AEP felt that PURA only requires the comparison of the price of power, and the commission has the discretion to make this comparison outside the confines of the ECOM model. The capacity auction true-up should be done outside of the ECOM model because using the model is administratively burdensome, subject to error, and requires more care in making adjustments. AEP also stated that the capacity auction prices for the individual products must be calculated and then applied to the actual MWh sales by product during the true-up period, rather than applying an average market price. AEP further stated that ECOM is very sensitive to actual fuel costs and MWh generation, and the capacity auction true-up process should account for this by substituting actual fuel costs and actual MWh sales for ECOM model inputs.

OPC and ARM replied that the commission should require an updated ECOM model run, but they argued that such run can be adjusted only for changes in the market price, not for updated sales and costs.

OPC disagreed with Reliant's argument that the purpose of the capacity auction or wholesale true-up is to ensure that the APGC receives the same margin from the capacity auction as the ECOM model predicted. OPC replied that the purpose of the wholesale true-up is to measure the difference between the revenue received by the APGC during the period from the start of competition to the time of the true-up and its forecast regulated revenue requirement during the same period. OPC claimed that Reliant's proposed calculation has no relation to the wholesale true-up described in PURA.

Reliant reiterated in its reply comments that the only way to calculate the capacity auction true-up is to apply the fixed cost contribution assumed in the ECOM model. Reliant argued that the language in PURA §39.262(d)(2) included assumptions about the cost of capacity, the cost of fuel, and sales. These power-cost projections resulted in an expected contribution to reduce stranded costs. According to Reliant, simply computing a dollar per MWh price from the capacity auction, as OPC and ARM argued, leads to a meaningless comparison because it tells nothing about the actual contribution available to reduce stranded costs. Thus, Reliant believes it is necessary to update the sales volume and fuel costs to calculate the contribution that results from the capacity auction. This can be done by first multiplying the dollar-per-MWh price an APGC will receive in the capacity auction times the APGC's actual total sales volumes, and then subtracting actual total fuel costs. The contribution from the revenues at the capacity auction price can then be compared to the contribution in the ECOM model. Reliant believes that OPC's and ARM's suggested method creates a mismatch of inputs and thereby distorts the true amount of stranded costs. The mismatch occurs because the calculation that OPC and ARM propose would include the prices from the capacity auction, but the sales volumes and fuel costs from the ECOM model. This creates the possibility that the capacity auction's contribution to stranded costs could be significantly overstated or understated. Reliant noted that in Senate Bill 7, the legislature allowed utilities to recover their stranded costs, but provided that they should not over-recover those stranded costs. Reliant replied that under OPC's and ARM's proposal, the APGC would almost certainly under-recover or over-recover stranded costs, because the actual sales volumes and fuel costs will undoubtedly vary from the amounts in the ECOM model. As it did in its comments, Reliant provided in its replies numerical examples illustrating its contentions. Reliant argued that because OPC's and ARM's narrow interpretation of PURA §39.262(d)(2) would generate inaccurate numbers for purposes of the true-up, that interpretation should be rejected.

The commission concludes that PURA §39.262(d)(2) does not mandate that the capacity auction true-up calculation be done within the context of the ECOM model. The purpose of PURA §39.262(d)(2) is to reconcile and update the effects of power costs on revenues, and no requirement to use the ECOM model for this purpose is specified in the statute. Further, with regard to the consideration of fuel costs, when interpreting the phrase "power cost projections" in PURA §39.262(d)(2), it is appropriate to interpret the term to include not only market revenues, but also the fuel costs that are part of the regulated revenue requirement. Because the purpose of the capacity auction true-up is to reflect actual power costs for 2002 and 2003, the way to achieve this objective is to use updated, actual data for power costs that include the effects of fuel. To do so is comparable to the commission's decision in Docket Number 22344, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA* §*39.201 and Public Utility Commission Substantive Rule* §*25.344*, in which the commission established updated gas prices and then reflected those updated prices in both the market-revenue calculations and regulated-revenue calculations of the ECOM model. The commission believes it is logical to assume that the legislature intended that fuel costs be updated because failure to do so could conceivably lead to unfair and unpredictable results for one set of parties or the other, as noted by Reliant. Another way to understand this point is to assume an extreme hypothetical—for example, assume that the use of the capacity auction results in the true-up did not occur until, say, 2025. To get a correct ECOM result, actual sales and fuel costs would have to be used for all the intervening years. Otherwise, the result would be meaningless, because the original projected data would not be comparable to actual, realized data.

Similarly, the commission agrees that it is appropriate to adjust sales figures in the ECOM model for comparison to capacity auction prices. Reliant gives examples in its reply comments showing that if the sales and fuel amounts are not adjusted with market revenues, the result can be either a benefit or a detriment to a company, depending on the direction and magnitude of the changes to the inputs. The commission does not presume that the legislature intended to have such an unpredictable and potentially unfair result.

Additionally, calculating the capacity auction true-up without the use of the ECOM model avoids various controversial issues related to use of the model, including issues related to the "Plant Economics" sheet in the model, questions regarding the generation-mix inputs, and other issues. The commission therefore has revised the rule to provide for calculation of the capacity auction true-up outside of the ECOM model. The commission finds that Reliant's and AEP's recommended approach, in which aggregated capacity auction revenues, actual fuel costs, and sales amounts are compared to data from the ECOM model, is appropriate. The rule has been modified to incorporate this change.

Preamble Question #2: Should the final rule incorporate criteria for determining whether a utility has used good-faith attempts to renegotiate above-cost fuel and purchased power costs as required by PURA §39.252(d)? If so, what should those criteria be?

TIEC and Cities supported the incorporation of specific criteria, but stated that the criteria should not be exclusive and the commission should make the determination on a case-by-case basis. The commission should preserve the flexibility to examine a wide range of utility actions that may impact the amount of a utility's stranded costs, including actions of its APGC or affiliated retail electric provider (AREP).

OPC, ARM, TXU, and Reliant agreed that specific criteria should not be incorporated into the rule to measure compliance with PURA §39.252(d). Reliant stated that each utility has a unique set of fuel and purchased power contracts, and the determination as to whether the utility has made a good-faith attempt to renegotiate its contracts can be determined only on a case-by-case basis. ARM suggested that the commission should consider the utility's management of its fuel and purchased power contracts, and the exercise of any discretion permitted by any contract to lower costs. TXU added that the commission should use a case-by-case approach because each utility will have contracts with different terms and conditions, and the legislature chose not to establish any specific criteria.

The commission believes that specific criteria for determining whether a utility has used good-faith attempts to renegotiate above-cost fuel and purchased power costs should not be incorporated in the rule to measure compliance with PURA §39.252(d). That determination should be made on a case-by-case basis. Therefore, no change to the rule has been made.

Preamble Question #3: The definitions of market price used in subsection (j) of the proposed rule use the same mix of power products (i.e., based on a three-year full requirements request for proposal and 12 months of capacity auction products) developed in the price to beat rule (Substantive Rule §25.41) to permit adjustments to the price to beat. Is this the appropriate method to determine the "prevailing market price" or is another method more appropriate? If this method is appropriate, should the prices used be forward looking or should they be historical prices?

Nearly all of the commenters expressed concerns about the proposed methodology for determining the prevailing market price used in the reconciliation (the "retail clawback") between the price to beat (PTB) rates charged by the AREP and the market prices for residential and small commercial customers. Some commenters proposed alternative methods to determine the prevailing market price. The utilities generally supported an approach that would involve compilation of retail market prices by an independent third party. However, ARM, TIEC, and OPC advocated basing the market price solely on the capacity auction results, shaped for retail PTB loads. Specific comments on the retail clawback are discussed below.

Modified Capacity Auction Method

ARM argued that the methodology in the proposed rule is not appropriate because it utilizes the results of "phantom" requests for proposals (RFPs) to serve load that responding bidders will not actually be permitted to serve. Cities also questioned whether the contemplated RFPs for hypothetical load would result in competitive bids that accurately reflect true market prices. Failure to use true market prices increases the likelihood that the retail clawback will be undervalued. ARM further contended that too much research and analysis would be required to respond to a hypothetical RFP. ARM recommended determining the prevailing market price solely by reference to the winning bids for power purchased in the capacity auctions, shaped to serve a residential or small commercial customer, as appropriate. ARM claimed that this method not only bases the determination of market price on actual transactions, but also provides an important check on any incentive a utility may have to "game" the capacity auction prices. ARM explained that tying the market price used in the wholesale clawback to that used for the retail clawback provides a necessary check on any potential attempts by the utilities to manipulate the true-up. Accordingly, ARM recommended deleting the definitions of residential market price of electricity and small commercial market price of electricity in proposed subsections (c)(7) and (c)(9), respectively, and instead using definitions that would equate to the baseload capacity auction price of wholesale electricity.

In its initial comments, TIEC recommended specifying that the three-year full requirements RFP require firm bids for a prospective three-year period. TIEC explained that the forward-looking requirement would ensure that bona fide bids would result. TIEC added that the utility should have the burden of proof that it conducted a legitimate, widely advertised RFP. TXU objected to this recommendation, noting that it would exacerbate problems associated with using wholesale prices to determine retail rates. Further, TXU argued that using firm bids for a three-year period would be inconsistent with the view that PURA requires historical price comparisons for the true-up. In its reply comments, TIEC recognized that obtaining bona fide, binding offers through an RFP may prove to be too difficult. Consequently, TIEC agreed with ARM that capacity auction prices alone, shaped for residential and small commercial customers, should be employed as the starting point for developing retail market prices. TIEC also agreed that the same capacity auction market prices should be used in both the capacity auction true-up and the retail clawback in order to avoid gaming. OPC initially supported the market price definition in the proposed rule. However, in its reply comments, OPC agreed with those parties advocating use of capacity entitlements alone, properly shaped for each customer class, as a proxy for the retail market price.

ARM and TIEC recommended that the true-up rule establish the principle of using capacity auction prices as the basis for market prices, and that an implementation workshop be convened to address the specifics of the transformation and shaping for residential and small commercial customers. TIEC also suggested that the auction prices be shaped to serve an industrial customer if the rule requires the ECOM model to be rerun for the capacity auction true-up per PURA §39.262(d)(2). Cities added that the capacity auction products and prices must be appropriately balanced to reflect the specific utility's discrete load shape, because the capacity auction products reflect supply-side components. In addition, TIEC noted that it is more appropriate to use the entire 2002 and 2003 time frame for the capacity auction portion of the calculation rather than the one-year period in the proposed rule.

Entergy replied that these comments by Cities, ARM, and TIEC identify real limitations in the proposed rule, but that none of the proposed modifications would calculate a true retail price or resolve the fundamental problems inherent in attempting to use wholesale market indicators to derive retail prices.

Moreover, AEP replied that the concern over gaming the capacity auction is not realistic. AEP suggested that this idea rests on the unsupported premise that the utility, rather than the market, would control the auction prices. AEP also said that it means that the utility would engage in the economically perverse behavior of minimizing its gains from the capacity auction. Reliant and TXU also rejected ARM's arguments that a utility could game the capacity auctions by flooding the market with capacity to depress prices. Reliant questioned why retail electric providers (REPs) represented by ARM fear depressed prices for the wholesale electricity they will buy. Reliant stated that regardless, a balancing of the retail and wholesale clawbacks will occur if actual, observed market prices (i.e., Electricity Facts Labels) are used because retail prices will reflect wholesale prices and wholesale prices will be influenced by the capacity auctions. Moreover, TXU suggested that gaming is not a concern because the capacity auctions are conducted under the commission's rules. Entergy also opposed the use of capacity auction prices. In addition, Entergy argued against proposed modifications to capacity auction prices to reflect the cost of retail service because the load shaping process contemplated by TIEC and ARM would be complex and contentious.

Electricity Facts Label Proposals

Reliant, TXU, Entergy, AEP, and TNMP pointed out several shortcomings with the method in the proposed rule, most notably that it does not provide for a historical price comparison and does not capture all of the costs associated with providing retail electric service (e.g., line losses, ISO fees, capacity costs, ancillary services, taxes, and sales and administrative costs). AEP argued that the use of RFPs and/or capacity auction results is fundamentally flawed because these methods do not yield a retail price. AEP explained that the proposed calculation is based on prices for products traded in the wholesale market rather than the retail market. According to AEP, this will almost certainly understate the prevailing market price and, therefore, overstate the amount of the retail clawback. AEP also suggested that decisions regarding relative weighting or blending of RFP and capacity auction results could have a large and potentially arbitrary effect. Entergy emphasized that the rule must reflect all of the costs associated with serving retail load. Entergy noted that there are significant costs associated with converting a wholesale product into a retail product, and that the commission should rely on retail market price indicators to determine the clawback. Moreover, Entergy argued that in the order adopting the PTB rule, the commission recognized that the "representative power price" was intended to serve only as a benchmark to track market changes. TNMP stated that PURA §39.262(c) compares the PTB and the price of retail electric service, not the PTB and wholesale electricity price. TXU agreed that there should be a retail-to-retail comparison, noting that the methodology in the proposed rule would not even reflect an accurate cost of wholesale power. TXU claimed that a RFP issued by an AREP at a time when all other AREPs are issuing the same type of RFP, and for a purpose mandated by commission rule rather than an actual need for power, will not provoke a valid market response. TXU argued that bidders will know that the RFPs are not bona-fide requests, i.e., that they are not being issued with an expectation of purchasing power. Finally, TXU noted that the proposed methodology is not appropriate for non-generating entities such as TXU SESCO.

Reliant commented that there is inadequate specificity in the proposed rule to actually calculate the retail price surrogate, and that the proposed method would result in additional administrative costs and estimation error. Reliant also stated that it is unlikely that competitive REPs would enter into three-year contracts at this stage of the market. Moreover, Reliant noted that the associated price from a three-year RFP would reflect at least one full year of full-requirements retail service that falls outside the period being trued up. According to Reliant, the retail price surrogate as calculated under the proposed rule would not reflect the actual retail prices charged by competing REPs, nor would it result in a value that is comparable to the PTB.

Reliant, TXU, Entergy, AEP, and TNMP supported using an actual, observable retail market price to compare to the PTB instead of an administratively determined market price. The utilities generally supported using an independent third party, such as an accounting firm, which would be overseen by the Electric Reliability Council of Texas (ERCOT) or the commission, to compile market prices offered by REPs during the 2002-2003 period. The utilities suggested that the independent party could use Electricity Facts Labels and other information to obtain data on prices and calculate a weighted average of retail prices charged by all REPs to residential and small commercial customers within the AREP's service area.

More specifically, TXU recommended using prices stated on REPs' Electricity Facts Labels times the system average use for each class to calculate the average prices per kilowatt-hour (kWh) for residential and small commercial customers. TXU said that the overall market price should be calculated by weighting the number of customers served in the territory by each REP, including the AREP and provider of last resort (POLR), under each price times the average prices per kWh. TXU suggested that all REPs should be required to report, on a confidential basis, their customer count to an independent third party designated by the commission. These reports should be filed quarterly.

AEP also recommended that an independent entity act as a retail market price collection and calculation agent during the 2002-2003 period to gather the data necessary to support retail clawback calculations. AEP suggested that on a monthly basis, the calculation agent would collect all retail market prices and monitor PTB tariffs to calculate (tariff by tariff) the difference between a weighted average of actual market price offers taken and the PTB in each AREP's transmission and distribution utility (TDU) service area. AEP said the market price offers would be weighted by volume data available from the Electric Reliability Council of Texas (ERCOT) for each of the respective REP's offers. AEP suggested that the results would be subject to commission audit with any privileged data remaining confidential.

Reliant also preferred using an independent third party to collect data using Electricity Facts Labels to determine the prevailing market price. Reliant recommended revising subsections (c) and (j) such that the market prices for residential and small commercial customers in effect on January 1, 2004, as calculated by the independent third party, be compared to the PTB on that date. Reliant suggested that the market prices be obtained from pricing disclosures pursuant to §25.475(e), relating to Information Disclosures to Residential and Small Commercial Customers. Under Reliant's proposal, the difference between the PTB and market price would be compared to the statutory maximum of $150 per customer, multiplied by the difference between the number of applicable customers taking PTB service from the AREP in its affiliated TDU area and the number of customers being served by the AREP outside its affiliated TDU region on January 1, 2004.

If the commission chooses instead to use the capacity auctions to determine the prevailing market price, Reliant emphasized that all costs must be included and the estimated commodity cost must be calculated with appropriate consideration of the load shape of PTB customers. As initially presented, Reliant's proposal for the capacity auction method used data from the most recent capacity auction prior to the determination date to establish the commodity component of the retail price. However, upon reviewing the comments of other parties, Reliant recognized that because capacity auction prices are indicative of future markets, the prices from the most recent capacity auction prior to the determination date may not truly reflect retail prices on that date. Thus, Reliant recommended changing subsections (c) and (j) such that the market clearing prices from all capacity auction products delivered during the years 2002 and 2003 be used to determine the commodity component of the retail price. Reliant also proposed language to include line losses, fees, and taxes specific to serving residential and small commercial customers, respectively, as well as a $ 0.5 per kWh allowance for sales and administrative costs. Reliant further stated that even though the electric power price (i.e., commodity price before adjusting for costs of retail service) may be determined by observing capacity auction prices over a period of time, the retail clawback must still be determined using the number of customers on the PTB as of January 1, 2004 to comport with PURA §39.262(e). Reliant said this assures computational consistency between the amount of credit due to the TDU and the legislatively imposed cap which is determined by multiplying that number of customers, minus the number of customers obtained outside the TDU's service area, by $150. Thus, while Reliant maintained that its Electricity Facts Label proposal is the preferred method, a reasonable capacity auction approach is available.

Entergy suggested that, because the legislature explicitly required that capacity auction prices be used in one portion of the true-up (i.e., the reconciliation of PURA §39.262(d)(2)), it presumably did not intend that such prices be used in the retail clawback where they are not mentioned. Like the other utilities, Entergy preferred deriving the retail market prices using weighted prices from the Electricity Facts Labels and other market information gathered by an independent third party. However, Entergy also recognized that a properly structured RFP process could be a viable method for determining the market price so long as the bids were real bids (i.e., capable of being accepted) and the products being bid mirrored PTB service obligations and risks.

TNMP suggested that the methodology for determining the prevailing market price would be most promptly addressed through use of survey techniques to be proposed by each affiliated REP, based on the particular circumstances in that REP's service area, as approved by the commission.

TIEC contended that AEP's proposal for retaining an independent entity to calculate market prices may yield limited survey results due to confidentiality concerns, may be a cumbersome and costly approach, and may be subject to manipulation. ARM strongly opposed recommendations that the prices be obtained either from the Electricity Facts Label or compiled by an independent third party from prices charged by REPs. ARM objections to an independent third party administrator compiling pricing and customer load information included potentially large costs and administrative burdens on REPs to the benefit of the AREPs. Most important to REPs, ARM expressed concern that there is no way the commission can ensure the confidentiality of competitive REP's customer and pricing data provided to the commission. Cities said that it had no conceptual objection to basing the clawback calculation on a comparison of PTB prices and a weighted average of retail prices offered by competitors. However, Cities believed that this would require the disclosure of highly sensitive and confidential information that may be difficult to obtain for larger commercial customers. Further, it may not be possible for the commission to require disclosure of this information.

AEP responded, however, that the commission is accustomed to handling proprietary information, that PURA §39.352(f) contemplates that the commission may need to have access to confidential information, and that providing it is consistent with REP reporting requirements of PURA §39.352(c). AEP also pointed out that the customer protection rules also recognize the commission's authority to obtain confidential information. AEP argued that the commission has clear authority to obtain both the Electricity Facts Labels and the Terms of Service documents, which are the two primary sources for obtaining REPs' retail market prices. Entergy suggested that commission involvement would permit the discovery of market data, while administration by an independent third party could assure the confidentiality necessary to protect the data.

Some participants in the public hearing commented that the Electricity Facts Labels were not indicative of prices paid by commercial customers. ARM argued that the Electricity Facts Label is not representative of all the prices charged to small commercial customer loads because its ignores prices charged to customers whose load approaches the 1000 kW cutoff for the PTB load. In addition, ARM noted that the prices on the Electricity Facts Label are based on representative, not actual, consumption levels, and as such, do not reflect actual prices in the market. TIEC added that the utilities' Electricity Fact Label proposals are inadequate because the resulting prices reflect arbitrarily selected consumption levels that will not accurately reflect the actual price offered in the market to all PTB customers. TXU noted, however, that usage levels of approximately 84% of its customers fall within the Electricity Facts Labels usage levels of 1,500, 2,500, and 3,500 kWh per month. Therefore, TXU argued that the prices on the Electricity Facts Labels provide a reliable estimation of the prices available to the vast majority of PTB customers. For the small number of commercial PTB customers whose usage does not fall within the Electricity Facts Label levels, TXU suggested that REPs could submit rate information to an independent third party.

The commission finds that the modified capacity auction method proposed by ARM, TIEC, and OPC for determining market prices would be complex and difficult to administer. It would also likely lead to litigation over how to properly shape the capacity auction prices to retail load. Therefore, the commission agrees with those parties advocating the use of actual, observed market prices, rather than administratively determined prices, for comparison to the PTB rates for residential and small commercial customers. By using actual retail prices in the marketplace, there is no need to develop complex procedures for converting wholesale prices to retail prices. The Electricity Facts Labels will be an important source of this market data and can be supplemented by other information—such as customer counts, volume levels, and prices offered to customers that do not fall within the Electricity Facts Label usage levels—provided by REPs on a confidential basis to an independent third party designated by the commission. Additional information may need to be obtained from ERCOT for this purpose. REPs can also redact sensitive customer information and present aggregated information to protect confidentiality.

The commission prefers TXU's methodology for calculating the weighted average of prices during 2002 and 2003 on a quarterly basis to determine the prevailing market price. However, for reasons set forth below, the commission does not agree with TXU's proposal to include POLR and PTB rates in the prevailing market price. The commission amends the definitions of residential and small commercial market price of electricity in proposed subsections (c)(7) and (c)(9) accordingly (also see additional discussion regarding these definitions in *§25.263(c)—*

Definitions). Details regarding funding, oversight, timing, minimum switching threshold, and what rates to include in the comparison are discussed below.

Funding and Oversight

Most of the utilities suggested that either ERCOT or the commission oversee the independent third party, and that the costs be spread to all market participants. However, AEP, Entergy, and TXU agreed that such costs should be recovered from only the AREPs. AEP stated it would be appropriate for ERCOT to oversee the survey of retail prices and for all market participants to share in its funding, noting that PURA §39.151 provides adequate authority for this approach. AEP was not opposed, however, to having a third party contracted to carry out the survey with the commission's oversight and necessary funding reasonably allocated among and recovered from the AREPs. AEP suggested that a working group of affected market participants be established to collaborate and provide recommendations to the commission regarding a third-party agent and other processes and reporting requirements. Entergy recommended that the process be overseen by either ERCOT or the commission, or both, as long as it is actually conducted by an independent third party such as a reputable accounting firm. Entergy agreed with AEP that PURA §39.151 provides statutory authority for ERCOT to administer the program and to spread the costs to market participants. Entergy also stated that its affiliated REP would be willing to fund its share of the process if the commission determines that it should be funded only by AREPs. Entergy noted, however, that it would be fairer and more appropriate to spread the costs to all market participants and, hence, to all customers. In response to questions at the public hearing concerning the commission's ability to require REPs to pay for the independent third party, TXU also stated that it is willing to share such costs with other AREPs and, if cost-sharing is agreed to by the utilities, no question of the commission's authority arises. In the alternative, TXU commented that the commission has in the past required utilities to pay for an independent witness in a proceeding. Reliant added that in previous proceedings at the commission, outside consultants have been retained for specific purposes under contracts executed by a number of the parties to a particular proceeding. Reliant explained that in the past, consultants performed their work under the direction of the Staff, but the consultants' fees and expenses were paid by the utility and often recovered through rates or other mechanisms. Reliant suggested that a similar procedure could be employed to compute the retail clawback. Reliant said it is agreeable to entering into a multi-party contract to hire the needed independent third party and to paying its share of the expenses incurred under the contract. Entergy and Reliant did not anticipate that the costs would be significant.

The commission agrees with the utilities that an independent third party, such as a reputable accounting firm, should be used to collect the necessary information and calculate the prevailing market price. It is appropriate for the commission to oversee this process and thereby ensure that the methodology is applied in accordance with this rule and commission orders. The commission appreciates the compromise position presented by the utilities to agree to pay for the costs associated with this independent third-party process. The commission agrees with Entergy and Reliant that these costs should not be significant. Moreover, because of the commission's oversight role, the commission will ensure the costs are reasonable. Further, because the retail clawback is a responsibility of the AREP and TDU, it is not appropriate that other market participants should have to bear the cost of hiring the third-party consultant. Therefore, the commission finds that only the AREPs should pay for the costs of determining the prevailing market price of electricity. The commission adds a new definition for "independent third party" to the rule and will initiate a proceeding to designate the independent third party and determine the cost allocation between AREPs.

Timing Issues

Numerous commenters emphasized that comparison of the PTB and prevailing market prices should reflect the period through January 1, 2004, not a "snapshot" on a single date (i.e., January 1, 2004). Entergy stated that the proposed rule compares the PTB and market prices on January 1, 2004, but that PURA calls for the comparison to be made during the period the PTB is in effect through January 1, 2004. Entergy claimed that, to be accurate, the clawback reconciliation must be based on a periodic comparison of the PTB and market prices—perhaps on a quarterly basis—during 2002 and 2003. Entergy noted that the recent volatility in natural gas prices illustrates the importance of considering prices over the entire period and not simply at one moment in time. TXU agreed that the proposed rule is flawed in providing for a true-up based on a PTB snapshot. TNMP also questioned why the rule provides for the determination of the market price on a single day when the definition of market price anticipates use of the simple average of bids for a three-year period. AEP stated that inter-temporal issues make the ultimate timing of the price comparison incorrect because it creates a timing mismatch. AEP explained that the proposed calculation incorrectly compares PTB volumes from 2002 and 2003 to market prices obtained at the beginning of 2004 for the period 2004 to 2006. This results from the rule's use of a forward-looking RFP.

OPC also argued that the use of a January 1, 2004 market price and the PTB on that particular date, rather than the actual historical prevailing market prices and PTB applied during 2002 and 2003, is inconsistent with PURA §39.262(e). Reliant commented that, contrary to what OPC argues, the statute does not require the use of data from the years 2002 and 2003; it only requires that the prevailing market price and the PTB be from "the same time period," and that requirement can be met by using the January 1, 2004 date for both. Reliant argued that there is no basis for OPC's assertion that "the market prices in 2002 and 2003 are likely to be significantly lower than in 2004, whereas the PTB in 2004 is likely to be much lower than the PTB in 2002 and 2003." Reliant suggested that it is more likely that the spread between the prevailing market price and the PTB will be relatively unchanged from the start of customer choice to January 1, 2004, because of allowable fuel and purchased power adjustments to the PTB. Thus, Reliant contended that it makes sense to use data from that date for measuring the retail clawback.

The commission agrees with the majority of parties recommending that the PTB and market prices be compared on a periodic basis through January 1, 2004, rather than on January 1, 2004. PURA §39.262(e) states that "To the extent the price to beat exceeded the market price of electricity, the affiliated retail electric provider shall reconcile and credit to the affiliated transmission and distribution utility any positive difference between the price to beat established under Section 39.202 … and the prevailing market price of electricity during the same time period." The commission believes that this provision requires a reconciliation of the PTB and market prices during the same period (i.e., the period from 2002 through 2003), rather than a snapshot comparison on January 1, 2004.

Minimum Switching Threshold

Entergy and AEP proposed that an AREP should be exempt from the retail clawback if customer switching has not exceeded a minimum threshold of 5.0% as of January 1, 2004. The actual switching rate for this calculation would be calculated in the same manner specified in §25.41(i). AEP claimed that the 5.0% threshold captures those circumstances where there is so little customer switching that it can be fairly concluded that the PTB is the market price for that area. In these cases, AEP argued, there would be no need to calculate the retail clawback. Entergy proposed using a preliminary threshold assessment, based on visible customer switching data and wholesale prices, to determine whether to conduct a more thorough clawback assessment. Under Entergy's proposal, if the commission determined that less than 5.0% of residential and small commercial customers have switched to non-affiliated REPs, no further clawback investigation would be necessary. Entergy suggested that the commission could also employ an assessment based on wholesale market data such as hourly balancing energy transactions during 2002 and 2003. Entergy claimed that because these data would not include retail costs, it would understate the actual market price of retail service. If the wholesale benchmark exceeds the PTB, Entergy argued that the commission could determine with confidence that no further clawback was required. Entergy contended that these preliminary threshold assessments avoid the necessity of a full clawback proceeding if the market has not developed in some areas.

OPC commented that PURA does not allow for a minimum switching threshold. According to OPC, if few customers switch, at the very least there should be a calculation of the excess profits of the affiliated REP and a commission finding of whether the amount is material enough to require a refund.

The commission recognizes that if there is very little customer switching to competitive REPs in an area, it could indicate that the PTB is at or below the market price. However, there could be numerous reasons—besides price—why customers do not select alternative providers for electricity. Likewise, competitive REPs may avoid certain markets for reasons other than not being able to compete with the PTB. Obviously, if there are no customers switching and no

REPs making offers in an area, there is no need for the retail clawback because there is nothing to compare to the PTB. The commission is reluctant at this point, however, to establish an arbitrary level for a minimum switching threshold. Nonetheless, if there is evidence that a market has not developed in a certain area, the commission may consider good cause exceptions, on a case-by-case basis, to the retail clawback provisions of the rule.

POLR and PTB Prices

AEP suggested that market price should include offers by competitive REPs, PTB rates, POLR rates, and rates provided to state institutions. TXU also commented that a determination of the prevailing market price should take into account the rate that all customers have chosen to pay, including PTB and POLR customers. TXU claimed that if the market price were determined by ignoring the PTB rate, the result would be skewed.

Cities emphasized, however, that it was absurd to include PTB and POLR customers and prices in the calculation of the benchmark-unregulated price because it was contrary to legislative intent to include regulated prices and it would eliminate the significance of the clawback. Cities was especially critical of AEP, which queried how price could be determined in a market in which the only price was the PTB because AEP's hypothetical only demonstrated that a clawback would not apply under its scenario. ARM and OPC agreed that it would be inappropriate to use the PTB or POLR rates to estimate the market price because those are regulated rates approved by the commission, not market-based rates. OPC added that including the PTB in the market price would dramatically overestimate market prices due to the dominance of the PTB in the weighted average. OPC further argued that the prices of premium electricity, such as green power, must be excluded. TIEC added that it would defeat the purpose of the PTB clawback to include regulated rates such as POLR and the PTB in the market price calculation.

The commission disagrees with AEP and TXU that PTB and POLR rates should be included in the determination of prevailing market price. The commission interprets PURA §39.262(e) to make a distinction between the price to beat and other prices in the market when it provides that "to the extent that the price to beat exceeded the market price of electricity, the affiliated retail electric provider shall reconcile and credit to the affiliated transmission and distribution utility any positive difference between the price to beat ... and the prevailing market price." Therefore, the commission concludes that the PTB should not be included in determining the prevailing market price for purposes of the retail clawback. Furthermore, the POLR rate is a regulated rate that requires approval by the commission. It is not expected that customers will voluntarily select the POLR price, but rather customers will default to the POLR if their service is terminated by their chosen REP, either for non-payment or if the REP goes out of business. POLR service is unique in this sense and the price should reflect the cost of providing the safety net accorded by POLR service. Therefore, POLR rates should not be considered in determining market prices.

Applicability of Retail Clawback to Non-Stranded Cost Utilities

AEP argued that the rule should not require non-stranded cost utilities, such as Southwestern Electric Power Company (SWEPCO) and West Texas Utilities (WTU), to participate in the retail clawback. AEP claimed that PURA makes clear that the overall purpose of the true-up is to ensure that a utility may not over-recover stranded costs. Moreover, AEP stated that the retail clawback provision is designed to prevent over-recovery of stranded costs. AEP also noted that non-stranded cost utilities will have a PTB that is unlikely to exceed market prices by any appreciable extent.

The commission disagrees with AEP. The purpose of the retail clawback is to capture and return to customers the price differential between the market price of power and the PTB during the period between the start of competition and the time of the true-up. If there is little price differential between the market price and the PTB for non-stranded cost utilities, such as SWEPCO and WTU, then the amount returned to customers will simply be less.

Comments on specific sections of the rule:

§25.263(a)—Purpose

TXU recommended replacing the phrase "excess revenues" in subsection (a) with either "excess profits" or "excess net revenues" to recognize the costs an AREP incurs in providing service. TXU noted that an AREP's revenues cannot be considered until all costs incurred in producing the services that generated the revenues are covered. Accordingly, TXU recommended revising subsection (a) to refer to "the level of excess profits from customers" rather than "the level of excess revenues."

The commission agrees in part. The portion of the purpose statement discussed in TXU's comment concerns the retail clawback provisions of PURA §39.262(e), which provides that the AREP must credit to the affiliated TDU any positive difference between the PTB, reduced by the nonbypassable delivery charge, and the prevailing market price of electricity. However, because the statute addresses only nonbypassable charges, the commission does not believe that further adjustments to account for other AREP expenses are appropriate. The commission has revised subsection (a) to refer to revenues net of nonbypassable delivery charges. No other changes were made in response to this comment.

Reliant commented that, as currently written, the proposed rule could be interpreted to preclude the recovery of regulatory assets that are not already being recovered through a transition charge (TC). In its securitization case, Reliant was specifically permitted to seek in future proceedings stranded cost recovery of generation-related regulatory assets that it did not seek to recover in its initial securitization case. The true-up proceeding clearly involves the calculation of stranded costs, and this provision of the proposed rule should be written to comport with the financing order issued in Reliant's securitization case, PUC Docket Number 21665, *Application of Reliant Energy, Incorporated for a Financing Order to Securitize Regulatory Assets and Other Qualified Costs*, (June 1, 2000).

In its reply comments, ARM agreed with Reliant that the rule should not be read to preclude recovery of generation-related regulatory assets specifically permitted by the commission to be considered in a proceeding pursuant to a securitization case. ARM recommended a modification to Reliant's proposed language to ensure that it is not interpreted to include regulatory assets that have been approved for securitization but not securitized.

The commission agrees with Reliant and ARM that regulatory assets not previously approved for securitization are eligible for recovery in the true-up proceeding and amends the proposed rule as recommended by ARM.

§25.263(b)—Application

EPE requested that the rule be revised to clarify that it has no claim for cost recovery and is exempt from the provisions of PURA Chapter 39 pursuant to PURA §39.102(c) until the end of the ten-year base-rate freeze imposed under Docket Number 12700, *Application of El Paso Electric Company for Authority to Change Rates*. EPE further requested revisions to subsections (d)(2), (l)(1), and (l)(2) to reflect that EPE is not subject to the portions of the true-up that relate to stranded cost determination and recovery.

The commission does not believe any rule changes are needed to address EPE's concerns. First, the rule is written in a manner that provides for later true-ups for utilities that do not go to competition on January 1, 2002. For example, subsection (e)(4) provides that the commission may update orders issued in a generic true-up proceeding for any utility whose customers are not offered customer choice on January 1, 2002. Further, the provisions of subsection (d) explicitly address which components of the true-up proceeding apply to stranded and non-stranded cost utilities; specific provisions for EPE are unnecessary. Accordingly, no changes were made in response to these comments.

§25.263(c)—Definitions

§25.263(c)(1) (definition of capacity auction total price of power)

TXU suggested modifying the definition for "capacity auction total price of power" in order to account for the fact that the APGC will be financially responsible for any scheduled energy, regardless of whether it is actually delivered. ARM agreed with TXU's insertion of the word "scheduled" in this definition.

The commission agrees with TXU and ARM and has inserted the word "scheduled" into the definition of capacity auction total price of power.

Proposed §25.263(c)(3) (definition of mitigation)

Reliant stated that the current definition of mitigation includes the term "commission order," which is a vague term despite being intended in this context to incorporate the transition cases that utilities such as Reliant entered into. Therefore, Reliant recommended that the definition be rewritten to include "issued after 1996 that approved a utility's transition case" at the end of the definition.

The commission agrees that Reliant's language adds clarity to the definition of mitigation and adopts the revision.

Proposed §25.263(c)(4) (definition of net value realized)

TIEC argued that the definition of "net value realized" should reflect the value of any emissions credits and all other items from the PURA §39.251(3) statutory definition of "generation assets" that are associated with the sale. Also, any tax impacts of the asset sale should be included in the calculation of the net value realized. TXU agreed with TIEC's recommendation to include all items in PURA §39.251(3) in the definition of "net value realized." TXU stated that TIEC was unclear in its recommendation to include tax impacts of the asset sale in the calculation of net value realized. Nevertheless, TXU recommended that TIEC's recommendation be rejected because "net value realized" for an asset sale should be exclusive of taxes just as net value realized in a stock sale does not include tax impacts. Reliant responded that such a change is improper and unnecessary because the book value of the generation assets does not include any tax effects, and book value must be compared to a sales price, which is also not adjusted for tax effects. The terms generation assets, market value, and stranded cost are all clearly defined terms in PURA §39.251, and the concept of book value is a well known and clearly understood term in the utility context. None of these terms includes consideration of tax effects.

The commission believes that because "net value realized" refers to compensation paid by a buyer for generation assets, and generation assets are defined in PURA §39.251(3) and in PUC Substantive Rule §25.5, no additional definition of generation assets is necessary. With regard to the inclusion of tax effects, the commission agrees with TXU and Reliant that "net value realized" is exclusive of taxes and, accordingly, no change to the rule is necessary.

TIEC also argued that to the extent that a utility and its APGC or unaffiliated PGC encumber generation assets in a manner that reduces their value, such encumbrances might violate the statutory directive of PURA §39.252(d). TIEC recommended that the commission reserve the right to adjust the net value realized to reflect the impact of any limitations imposed by the seller on the purchaser's use of the acquired assets. TXU replied that PURA §39.262(h)(1) does not give the commission the authority to second-guess the outcome of the sale process and TIEC's recommendation should be rejected.

The commission declines to revise the definition as recommended by TIEC. The rule provides a mechanism for adjusting the book value of generation assets in the event that the requirements of PURA §39.252(d) are not met. No further mechanisms to address such an eventuality are required.

Proposed §25.263(c)(6)(definition of regulatory assets)

TNMP commented that the definition of "regulatory assets" contains an offset for the "applicable" portion of generation-related investment tax credits per the statute. TNMP argued that this off-set could result in a normalization violation of the Internal Revenue Code of 1986 and suggested adding "provided an offset by such applicable portion does not result in a violation of the normalization rules of the code" to the end of the definition. TIEC replied that a change to the definition would be appropriate only if the rule also requires utilities to seek private letter rulings from the Internal Revenue Service that allow them to treat their investment tax credits in a manner that minimizes ECOM and the likelihood of such normalization violations.

The commission does not believe TNMP's additional language is necessary. The definition of regulatory assets used in the rule is the same as that in the statute. Accordingly, no change to the rule has been made.

Proposed §25.263(c)(7), (c)(8), (c)(9), and (c)(10) (definitions of residential market price of electricity, residential net price to beat, small commercial price of electricity, and small commercial price to beat)

TNMP argued that if the commission does not abandon the use of a RFP, it needs to clarify the time period in the proposal. TNMP stated that the PTB, which includes a fuel component, would change over time. Therefore, TNMP was unclear why it would be appropriate to use the PTB on a single date as a point of comparison. TNMP also argued that it is unclear whether the three-year period runs from January 1, 2004 or runs from 2002 and includes January 1, 2004. Finally, TNMP commented that if the average is to be compared to the cost on a single day, it might be reasonable to clarify the rule to determine the simple average of costs on a daily basis. OPC, in conjunction with its response to Preamble Question #3, suggested that the definitions should be revised to delete the January 1, 2004, reference consistent with a change that would compare the PTB revenues in 2002 and 2003 to the product of PTB sales in 2002 and 2003 times the prevailing market prices (developed as specified in the PTB rule) during 2002 and 2003. AEP commented that the definition incorrectly compares PTB volumes from 2002 and 2003 to "market" prices obtained at the beginning of 2004 for the period 2004 to 2006. Entergy suggested that the definition of market price is based on a snapshot comparison with the price to beat on January 1, 2004, rather than a comparison over the years 2002 and 2003. Entergy suggested that the clawback reconciliation must be based on a periodic comparison of the price to beat and market price—perhaps on a quarterly basis—during 2002 and 2003. TXU recommended modifying the definitions for residential and small commercial market price of electricity in proposed subsections (c)(7) and (c)(9), respectively, to compare the average weighted PTB rates in effect during the entire true-up period (i.e., from January 1, 2002 through January 1, 2004).

Several commenters, in conjunction with their responses to Preamble Question #3, suggested alternative definitions. TNMP contended that PURA §39.153(a) exempts entities such as TNMP from the capacity auction; therefore, it would only fit under a portion of the definition. TNMP suggested that the commission adopt a definition that uses data from actual sales occurring in the affiliated REPs' service areas; this would provide a reasonable estimate of the market price available to PTB customers if they chose to switch to a nonaffiliated REP from the affiliated REP. Entergy commented that the market price definition is not based exclusively on retail market price indicators, but instead is based on an average of the results of RFPs to serve retail customers and wholesale capacity auction prices. Entergy argued that there would be significant costs to transform wholesale costs into retail costs. Entergy suggested using retail market indicators from the beginning. AEP argued that the prevailing market price should be measured in terms of prices offered to and accepted by customers in the retail electricity market. AEP maintained that the wholesale transactions do not incorporate all of the costs included in retail markets. AEP suggested that the weighted-average net market price of electricity should be computed from all price offers taken in the market, including PTB, POLR, and prices discounted for specific customer classes. Reliant commented that if capacity auction prices are to be used for estimating retail electric prices, these additional costs must be captured if a valid retail price comparison is to be made. Reliant recommended that actual, observable retail electric prices from the Electricity Facts Labels be used to compare PTB prices. In the alternative, Reliant commented that if the commission adopts a definition that is based on the estimated cost of providing retail service, all costs must be included and the estimated commodity cost must be calculated with appropriate consideration of the load shape of the PTB customers. TXU also commented that it does not make sense to make a comparison between a retail PTB and a wholesale market price, particularly because it ignores many of a REP's costs of providing service to customers. TXU suggested that an appropriate method for determining "market price" would be to calculate a weighted average of the prices charged by all REPs to their residential and small commercial customers within the AREP's service territory during the period covered by the true-up, including customers who choose to be served at the PTB and customers served by the POLR. TXU recommended that the average price per kWh for residential and small commercial customers should be calculated using the prices from the Electricity Facts Labels. ARM recommended deleting the definitions of residential market price of electricity and small commercial price of electricity and instead using a definition for market price of electricity that would equate to the baseload capacity auction price of wholesale electricity. TXU replied that using the capacity auction price does not reflect a retail-to-retail comparison. Reliant stated that ARM's recommendations do not make sense, and that they imply that REPs such as those represented by ARM will sell electricity to small commercial customers with varying load shapes at the energy cost to serve a high load factor industrial customer and with no markup for line losses, fees and taxes, administrative and selling costs, or profit. Reliant commented that ARM's recommendations also imply that REPs will sell electricity to residential customers at only a 7.0% markup to cover the costs of meeting variances in residential loads plus line losses, fees and taxes, administrative and selling costs, and profit. Reliant also commented that if, in fact, ARM does expect REPs to sell at essentially below-cost prices, then that will be reflected in the Electricity Facts Labels, which Reliant has recommended be used. TNMP replied that the proposed definition is inconsistent with the statute; the structure of the claw back provision depends on making a comparison between the PTB and the price of retail electric service. ARM strongly opposed recommendations that these prices be obtained either from the Electricity Facts Label or compiled by an independent third party from prices charged by REPs. ARM argued that the Electricity Facts Labels are not representative of all the prices charged to small commercial customer loads by REPs, because they ignore prices charged to commercial customers whose load approaches the 1,000 kW cutoff for PTB load. In addition, "the prices on the Electricity Facts Label are based on representative, not actual, consumption levels, and as such, do not reflect actual prices in the market." ARM objections to an independent third party administrator compiling pricing and customer load information included potentially large costs and administrative burdens on REPs to the benefit of the AREPs. Most important to REPs, ARM expressed concern that "there is no way the commission can ensure the confidentiality of competitive REPs' customer and pricing data provided to the commission." ARM also opposed inclusion of PTB or POLR rates in the determination of residential or small commercial market price of electricity. ARM argued that POLR and PTB rates are regulated rates, approved by the commission, and are not market rates.

Consistent with the commission's decisions with respect to Preamble Question #3 as previously discussed, the commission has modified the definitions of residential market price of electricity, residential net PTB, small commercial price of electricity, and small commercial PTB.

Proposed new §25.263(c)(14) (addition of definition for small commercial customer)

TXU recommended adding a definition for small commercial customer, which clarifies that unmetered guard and security light customers shall not be considered PTB customers for purposes of the true-up calculation in subsection (j)(5)(A). TXU noted that this is necessary to avoid the over-counting of customers because, under ERCOT procedures, a separate Electric Service Identifier (ESI ID) is assigned to unmetered guard and security lights instead of associating the lights with the service received by the customer. TXU added that the number of ESI IDs would far exceed the actual number of customers if ESI IDs are considered customers for the purposes of the true-up. Reliant agreed with TXU's recommended addition because there will be an over-counting of small commercial customers as of January 1, 2004 if a correction is not made.

The commission agrees with TXU and Reliant and has included additional language in subsection (j) to address the over-counting issue.

Proposed new definition of stranded costs

AEP commented that it believed that it would be appropriate for the rule to include a definition of stranded costs, which could track the statutory definition found in PURA §39.251(7).

The commission does not believe that a definition of stranded costs is necessary. Stranded costs are defined in PURA §39.251(7).

§25.263(d)—Obligation to file a true-up proceeding

Reliant commented that the rule should specify that Reliant's true-up application will be filed on January 12, 2004, as necessitated by its business separation plan previously approved by the commission in PUC Docket Number 21956, *Reliant Energy, Incorporated Business Separation Plan Filing Package*. Reliant stated that while it understands that the commission may desire to stagger the true-up application filing dates, particularly given the 150-day limitation in PURA §39.262(j), its AREP has been granted an option to purchase Reliant's generation assets at a market value determined under the Partial Stock Valuation Method based on the highest 30 consecutive trading days out of the 120 consecutive trading days prior to January 10, 2004. If Reliant were required to make its true-up filing on any day after January 12, 2004, there could be a difference between the value that Reliant actually obtains for its generation assets if sold to Reliant Resources, Inc. (Reliant's AREP) and the value of those assets used in the true-up proceeding.

The commission acknowledges the timing issue associated with the filing of Reliant's true-up application. However, the commission does not believe there is a need to address that issue in this rule; it will be addressed in the true-up filing schedule to be issued by the commission at a later date.

TIEC commented that the rule should be clarified to require that the TDU, PGC, and REP jointly make the true-up filing regardless of whether they are affiliated on the date the true-up application is required to be filed. In particular, TIEC noted that some utilities contemplate spinning off certain affiliates and thus an affiliate relationship may not exist between components of the previously bundled utilities on the date the true-up application is filed.

The commission disagrees. The terms AREP and APGC are defined in §25.5 to include successors in interest of an electric utility. Therefore, the terms as used in the rule are sufficient to capture a REP that was initially affiliated with a utility and subsequently spun off.

AEP and EGSI argued that the proposed rule goes too far in that it requires non-stranded cost utilities to participate in the retail clawback portion of the true-up. Utilities without stranded costs should be required to participate only in the fuel reconciliation portion of the true-up, and PURA §39.262(a) supports this view because the overall purpose of PURA §39.262 is to ensure that a utility does not over-recover stranded costs. The retail clawback promotes the objective of avoiding over-recovery of stranded costs by ensuring that, to the extent the PTB exceeds retail market prices, the excess is used to offset stranded costs. Requiring utilities that are not seeking to recover stranded costs to participate in the retail clawback, which is intended to avoid double recovery of stranded costs, is unfair. AEP also recommended that an AREP be exempt from the clawback if customer switching has not exceeded a minimum threshold as of January 1, 2004. AEP recommended that this threshold should be set at 5.0%.

ARM generally disagreed with these comments. ARM stated that most, if not all, APGCs will have a final fuel factor to credit or bill to the TDU and all AREPs will be charging a PTB subject to the retail clawback provisions of PURA §39.262(e). ARM commented that, for AREPs charging a PTB so low that competition is not likely to develop in their TDU's service area, the obligation to participate in the retail clawback should apply only if a minimum threshold of switches is met. ARM recommended that the threshold be no greater than 5.0% of the PTB customers served by the AREP.

TIEC also disagreed with commenters who suggested that non-stranded cost utilities should not be required to participate in the retail clawback. TIEC argued that those commenters' claims that PURA §39.262 is intended to address stranded cost recovery only gloss over the fact that PURA §39.262 also addresses disposition of final fuel balances. The retail clawback is intended to protect PTB customers from paying excessive rates through the operation of the PTB.

The commission disagrees with commenters suggesting that the retail clawback applies only to non-stranded cost utilities. The commission interprets PURA §39.262(e) to be a mechanism that ensures utilities do not benefit if their rates during the first two years of competition exceed market rates. However, the commission agrees that in some cases the PTB may fall below market prices and few customers will have a financial incentive to switch providers. The number of customer switches is therefore likely to be very low, or none at all. As previously discussed in the commission's decisions with respect to Preamble Question #3, the commission may consider good cause exceptions, on a case-by-case basis, to the retail clawback provisions of the rule.

TXU recommended addition of a new subsection (d)(4), which appears intended to relieve TDUs, AREPs, and APGCs from having to make the filings required by subsection (f)–(k) of the proposed rule if a commission order provides otherwise. Presumably, this suggested additional language is intended to address situations where a utility settles all stranded cost issues prior to the initiation of the true-up proceeding.

The commission disagrees with TXU. Where a commission order contemplates a deviation of the specific requirements of this rule, that order will control over the provisions of this rule. No specific language to address such an eventuality is needed.

§25.263(e)—True-up filing procedures

Reliant objected to the portion of subsection (e)(1) stating that each TDU, APGC and AREP "shall file all testimony and schedules on which they intend to rely" to the extent it suggests that the applicants cannot file rebuttal testimony or otherwise respond to issues raised by other parties. While Reliant agreed that it has an obligation to make a *prima facie* case for stranded cost recovery in its initial filing, it should not be required to anticipate all issues that will be raised by the parties to the proceeding and to file every document that is conceivably relevant to those potential issues. Rather, the true-up proceeding should be conducted to allow the applicants to file rebuttal testimony or other documents to address issues raised by the commission staff and intervenors. This is consistent with the commission's rules and long-standing commission practice in contested cases.

TIEC and ARM countered by stressing that the accelerated time frame for processing the true-up cases required that the intervenors and staff obtain as much information as possible in the initial filing. TIEC stressed reducing the amount of data collected through the discovery process. ARM stressed meeting the utility's burden of proof at the time of the initial filing. To address Reliant's concern, TIEC and ARM suggested that the rule be clarified by adding language stating that a true-up applicant is not precluded from filing rebuttal testimony that specifically responds to issues raised by other parties to its true-up proceeding.

The commission agrees with Reliant that the rule should not be written in a manner to suggest that an applicant is prohibited from filing rebuttal testimony. However, the commission also agrees that the initial filing should be sufficient to state a prima facie case and to provide parties with the information supporting a true-up application. The commission has altered the wording of the rule to address these concerns.

TIEC commented that the rule should include detailed filing requirements. TIEC was supportive of the commission prescribing a thorough and detailed filing package. The filing package should include specific requirements for schedules and workpapers and make provisions for electronic filings: Word format for testimony and Excel format for numerically calculated schedules and workpapers. Files with PDF extensions should be disallowed. TXU commented in opposition to TIEC's recommendation that computer file types be prescribed by the filing package. TXU claimed that PUC Procedural Rule §22.72(j) already adequately covers requirements for filing documents in electronic form.

The commission agrees with TXU that commission rules already adequately address requirements for electronic filings. The commission notes that it has not traditionally specified filing requirements in a rule and sees no reason to deviate from traditional practice here. The filing package for the true-up proceeding will therefore be developed after the completion of this rulemaking. No change was made in response to these comments.

AEP objected to the six-month advance notice of a utility's plan to use the ECOM model because the time period was overly lengthy and inflexible. For example, unforeseen events could require a utility to abandon an alternative closer to the true-up filing than six months. AEP proposed a 60-day notice and a good cause exception for a late filing.

The commission understands AEP's concerns about advance notice of an intention to rely on the ECOM model for stranded cost valuation. However, if an applicant intends to use the ECOM model, advance notice is required to ensure that sufficient time is available prior to the initiation of the true-up proceeding to determine whether updates to the model should be made and to quantify those updates if needed. To accommodate AEP's concerns to the degree possible, the commission has revised the rule to reduce the advance notice requirement to 90 days.

Reliant and TXU objected to proposed subsection (e)(3), claiming that the commission should not initiate generic proceedings to determine true-up issues, other than perhaps for certain standard inputs for the ECOM administrative model used to value nuclear assets under PURA §39.262(i). Consistent with the legislative intent expressed in Senate Bill 7, all the components of the stranded cost calculation are based on the individual applicants' circumstances. Cities, ARM, and OPC expressed support for the commission's retention of the ability to initiate generic proceedings where circumstances dictate. It is impossible to know, this far in advance of the true-up filings, exactly which issues will lend themselves to a generic hearing.

The commission agrees with Cities, ARM, and TIEC that the commission should retain the flexibility to conduct generic true-up proceedings in the event that common issues requiring common resolution develop. In particular, a generic proceeding will likely be appropriate in the event applicants intend to use the ECOM valuation method. The commission has not made any changes in response to these comments.

Reliant and AEP objected to the commission making a determination with respect to whether the APGC and AREP—in addition to the TDU—have complied with their responsibility under PURA §39.252(d) to reduce stranded costs and protect the value of their assets. They claim that the requirements of PURA §39.252(d) are limited to a bundled electric utility. Reliant, AEP, and TXU also maintained that PURA does not provide the commission with the authority to reduce the net book value of generation assets as proposed in the rule, and that this proviso must be stricken from the rule. AEP also argued that the rule should include a more definite statement of the standards against which compliance with PURA §39.252(d) would be measured. AEP recommended specifically that the rule state that the commission will evaluate whether "the electric utility's efforts demonstrate commercial reasonableness, good faith, and the use of normal business practices, as those terms are commonly understood in the context of commercial law." Finally, the utilities argued that the rule should include language prohibiting the commission from second-guessing a market valuation under PURA §39.262 (h) or (i).

ARM replied that because APGCs and AREPs are successors in interest of the former bundled utilities, they assumed the responsibilities of the former electric utility, including maintaining their asset values. ARM said it was absurd to believe that the legislature intended for these responsibilities to cease after 2001 and before the 2004 true-up proceeding. OPC disagreed with the utilities' comments concerning the commission's authority to reduce the net book value of generating assets. Because the definition of stranded costs is the net book value of generation assets over the market value of those assets, and the commission is not authorized to substitute its judgment for the market valuation of generation assets, PURA must intend for the commission to have the ability to adjust the net book value, the only other component of stranded costs.

The commission agrees with ARM that the responsibilities of the APGCs and AREPs continue through the true-up proceeding. The legislature could not reasonably have intended that the duty to safeguard asset values for the benefit of ratepayers be extinguished more than two years prior to the commencement of the true-up proceeding. Further, the commission agrees with OPC that reduction of the net book value of assets is a reasonable remedy for a violation of PURA §39.252(d). Nevertheless, the commission believes it appropriate to preserve the flexibility to impose another remedy if the circumstances at the time warrant. The commission disagrees with AEP that a more definite statement of the standards for assessing behavior of an electric utility and its affiliates is needed. The rule refers directly to PURA §39.252(d), which includes the "commercially reasonable" language advocated by AEP. Finally, the commission agrees with the utilities that the rule should include statutory language concerning the inability of the commission to substitute its judgment for a market valuation of generation assets determined under PURA §39.262(h) and (i).

TXU and Reliant objected to the required implementation of expedited discovery procedures in the true-up proceedings, arguing that administrative law judges (ALJs) already have the discretion to require such expedited procedures in individual cases. TIEC responded that an expedited discovery procedure is needed for intervenors and staff to effectively participate in the accelerated true-up procedures.

The commission agrees with TIEC that an expedited discovery procedure is necessary given the 150-day accelerated deadline for finalizing the true-up cases. While procedures for obtaining expedited discovery are available upon request under other rules, the commission believes that the short timelines in the true-up proceedings demand expedited discovery without the need for a specific request. No change was made in response to these comments.

AEP, TXU, and Reliant objected to granting the commission the discretion to extend the deadline for processing a true-up proceeding for good cause. Reliant emphasized that a staggered filing schedule is the appropriate way to address time constraints, assuming it is allowed to file its application on January 12, 2004, as required by its business separation plan. TIEC disagreed with AEP, TXU, and Reliant, asserting that the good cause exception may be needed to ensure thorough processing of the true-up cases, given the accelerated 150-day time frame allotted for finalizing each proceeding. Also, TIEC asserted that this approach is consistent with the commission's general operations.

The commission views the statutory requirement as directory rather than mandatory and therefore reserves the right to extend the 150-day deadline if circumstances warrant. However, the commission anticipates that the provisions of subsection (e)(6) will be used infrequently if at all and that most if not all true-up applications will be processed within a 150-day window. No change was made in response to these comments.

§25.263(f)—Quantification of market value of generation assets.

EPE stated that it need not file any true-up application required under subsections (f), (g), (i), and (k) because it has made no claim for stranded costs, has undertaken no ECOM mitigation measures, and is currently exempt from PURA Chapter 30. EPE proposed language to accomplish its exclusion.

The commission believes that EPE is already excluded and does not feel there is a need to alter the wording of this subsection.

§25.263(f)(1)(A)

Reliant, TNMP, and AEP argued that the commission should eliminate the requirement to report a sale of assets 120 days prior to the transfer on the basis that the reporting requirement is unnecessary and could hinder the consummation of some transactions. TXU suggested that rather than deleting this requirement, it could be modified to require the reporting of such a transaction within 30 days of closing. AEP was opposed to any reporting other than with the true-up filing.

Reliant observed that a detailed explanation of the transaction is unnecessary because the sale of assets is by definition a third-party transaction under a competitive offering. Reliant also emphasized that if the commission imposes an after-the-fact requirement, a mechanism must be in place to ensure the confidentiality of competitively sensitive information. TNMP stressed that if this provision is retained in the final rule, the commission should try to accommodate four concerns. Specifically, TNMP was concerned that 120 days exposes the company to a lengthy period for markets to change, that some bidders may consider this an added risk factor, that some bidders may pay more for a quick turn around, and that delays might be experienced if ancillary items are not limited to material items. AEP also argued that no advance notice is provided with the other valuation methods.

TIEC and ARM argued that the reporting requirement should be retained because it allows the commission to collect important information regarding an asset sale that will be needed to perform an accurate calculation of the utility's final stranded cost balance. ARM was agreeable to reducing the requirement to 30 days prior to the transfer. TIEC did not oppose modifying this requirement to allow after-the-fact reporting as proposed by TXU.

TIEC proposed that ancillary components such as fuel contracts, water rights, and emission allowances be broken out and priced separately. According to TIEC, the commission must have enough information to accurately quantify the net value realized from the asset sale and to assure that all the ancillary items included in the definition of "generation assets" are addressed in the true-up filing.

Reliant replied to TIEC that, as a practical matter, such a break-out will not be available in most cases. Reliant also noted that TIEC did not explain why this level of detail was needed. TXU replied that this break-out would be burdensome, and might reduce the purchase price. TXU added that it should be sufficient for the sales contract to specify general categories of items that are included in the sale, such as a description of the unit, property boundaries, inclusions of fuel and parts, emission allowances, etc.

The commission acknowledges the concerns raised by Reliant, TNMP, and AEP. Therefore, the commission has deleted the requirement that it be provided with an advance copy of any proposed transaction. However, in order for the commission to remain abreast of the utilities' activities, the commission has included a requirement that the commission be provided a copy of a transaction within 30 days of closing. In addition, the rule has been revised to explicitly permit the utility to file the required information confidentially. The commission also believes that the general categories of items suggested by TXU will be useful to properly understand and review the transaction.

§25.263(f)(1)(B)(iii) and §25.263(f)(1)(C)(ix)

TIEC argued that there should be a separate appraisal of any non-utility or non-generation assets (that are deducted from the market value of generating assets) to make sure that the net book value of these assets does not exceed their market value. The purpose of this proposal is to make sure that the market value of generating assets is not negatively influenced by a non-generation or non-utility asset.

AEP and Reliant disagreed and AEP quoted PURA §39.262(h)(2) and (3), which state that "the market value of each transferee corporation's assets shall be reduced by the corresponding net book value of the assets acquired…." TXU agreed with AEP and Reliant that the acquired assets should not be appraised.

The commission interprets the wording of PURA §39.262(h)(2) and (3) to specifically provide that the net book value of assets acquired in an exchange be used as an offset to the market value of a transferee corporation's assets. Therefore, no change to the rule has been made.

§25.263(f)(1)(C)(iv)

Reliant and TXU maintained that the valuation panel convened to determine if a control premium exists should not exclude bankers that have worked for the companies in cases related to the implementation of Senate Bill 7. Reliant argued that there is no reason to assume that bankers cannot balance the conflicting goals that a utility might have in comparison to a competitor such as Enron. In addition, Reliant and TXU contend that this provision may disqualify so many of the top ten banks that it may be impossible to assemble the valuation panel in the manner required by law. Both Reliant and TXU proposed that this provision be deleted.

Cities replied that even if the bankers could balance the interests of utilities and REPs in all cases, their ability to balance the interests of rate payers is not addressed. In addition, TIEC and ARM argued that this provision should be retained to assure the objectivity of the valuation panel. However, to address the concerns of Reliant and TXU, both TIEC and ARM were amenable to modifying the rule to allow a utility to petition for a good-cause exception to this requirement if it can demonstrate that the operation of the rule prevents the formation of the valuation panel as prescribed by PURA §39.262(h)(3).

The commission believes that the policy established in this clause of the rule is needed to maintain the independence and integrity of the valuation panel. However, the commission acknowledges that a good-cause exception to this requirement may be sought in the event a utility determines it cannot meet the requirement of this provision of the rule.

§25.263(f)(1)(C)(v)

TXU objected to the rule's application of the control premium to assets and not to common equity based on the company's interpretation of PURA §39.262(h)(3). TXU added that no control premium should be applied to the preferred stock and debt amounts, which the proposed rule and PURA appropriately define as the book value of those securities. Reliant generally agreed with TXU, especially with respect to the application of the control premium to common equity. However, Reliant also argued that the word "market" must be added back to be consistent with PURA §39.262(h)(3).

The commission believes that financial theory alternatively applies control premiums either to common equity or to invested capital, i.e., debt plus common stock and preferred equity, which also equals total assets. The specific application depends primarily on whether the ultimate objective is to value the equity interest for the stockholders or to value the underlying assets for the business. To illustrate the financial consequence of this simple dichotomy, consider the following two choices. If the interpretation of TXU and Reliant is valid that the 10% control premium applies only to equity, the implied premium applicable to the valuation of generation assets is a nominal 4.0%, assuming the generic UCOS leverage of 60% for TDUs (equity of 40%). If the interpretation of TXU and Reliant is not appropriate, however, and the 10% control premium applies to total assets, the implied premium applicable to the valuation of equity is more consistent with an empirical market-based figure of 25% to 30%. Even if leverage is presumed to be a much lower figure of 50% to reflect the higher risk of generation assets, the comparable impacts are only 5.0% for assets and still 20% for common equity, respectively.

The commission believes that the legislature had the more realistic interpretation in mind when determining the market value of generating assets. The premium should apply to assets and not to equity. The commission's rationale is simply to assure that the market value of generating assets is not unreasonably penalized and stranded costs over-recovered. To demonstrate the magnitude of the potential penalty and under-recovery that is inherent in the position taken by TXU and Reliant, consider the following recent transaction. On September 27, 2001, the Wall Street Journal (p. A-4) and the New York Times (p. e-9) reported the proposed acquisition of Orion Power by Reliant for a 40% control premium applied to common equity, or a purchase price of $2.9 billion. Alternatively, if only a 10% control premium had been applied to the minority equity, as proposed by TXU and Reliant in this rulemaking, the purchase price of Orion stock would have been recorded at only $2.3 billion for regulatory purposes. Hence, this regulatory requirement would create an artificial reduction of over $600 million relative to the actual market price of the company's stock, in turn fostering an equal understatement in the real value of its assets and causing an over-recovery of the utility's stranded costs by that amount. In a true-up setting, this arbitrary windfall would flow to stockholders, and not to rate payers. Consequently, the commission retains the rule's application of the control premium to assets.

Additionally, the inclusion of the word "market" is not needed in the rule, and is deleted.

§25.263(f)(1)(C)(vii)

Reliant and AEP objected to the inclusion of the phrase "and other admitted evidence" regarding the commission's determination of value based on the finding of the valuation panel. Reliant and AEP argued that PURA is clear that only the panel's decision determines market value, and as such the phrase is superfluous and confusing.

The commission rejects the positions of Reliant and AEP that the language is overly restrictive on the commission and not intended by the legislature. Accordingly, no change to the rule has been made.

§25.263(f)(1)(D)(ii)

TIEC proposed that the commission receive a copy of the utility's RFPs for the asset offer, as well as documentation of any public notices or other means used to publicize the offer. The commission needs this information to ensure that the market valuation accurately reflects the true value of the assets in question.

The commission adopts TIEC's proposal to document the utility's sale proposal.

§25.263(f)(1)(D)

TXU proposed that in addition to appraisals in valuing the exchange of assets, two other valuation methods be made explicit. These include a bona fide third-party transaction under a competitive offering, followed by an appraisal, or the inclusion of the exchange assets in the stock valuation or partial stock valuation methods.

The commission disagrees. PURA §39.262(h) sets out four limited, detailed mechanisms for valuing generation assets. Given the specificity of this provision, the commission does not believe the legislature intended that alternative mechanisms be permitted. No change was made in response to this comment.

§25.263(f)(1)(D)(iv)

TIEC proposed that this section should specify that the burden of proof in the true-up proceedings is on the utility to demonstrate that the offer was properly conducted and produced a competitive result. Reliant and TNMP again raised their concerns about the 120-day period for advance notice of sales.

The commission disagrees that a specific designation of the party with the burden of proof is needed. The utility will be the true-up applicant and has the burden of proof. Further, as already noted, the commission has deleted the advance-period notice and replaced it with a filing to be made 30 days after closing. Additionally, the rule has been modified to provide for confidentially of filings. No changes were made in response to these comments.

§25.263(f)(2)(B)

TIEC urged that if the ECOM model is used to determine stranded costs, adjustments to the ECOM model from the UCOS proceeding should be limited to the greatest extent possible. Specifically, TIEC proposed that the ECOM model rely on previously approved inputs such as administrative and general (A&G) expenses, operations and maintenance expenses (O&M), taxes, rate of return (ROR), discount rate, and so forth. Furthermore, TIEC proposed that utilities should not be allowed to update their ECOM models at all unless they accompany each update request with detailed documentation and explanation.

AEP replied that these recommendations are contrary to PURA because no such limitations exist concerning ECOM updates. TXU did not oppose TIEC's proposal that utilities using the ECOM model needed to justify any changes from model inputs previously approved by the commission. However, TXU did object to providing all computer runs because the output could be voluminous, most runs would not provide meaningful information, and in any case an electronic file would be provided.

The commission agrees with TIEC that if a utility requests an update to the ECOM model, proper documentation and explanation must accompany the true-up application. However, the commission also agrees with TXU that because an electronic version is provided, alternative runs do not also need to be provided. No change to the rule has been made.

§25.263(g)—Quantification of net book value of generation assets

§25.263(g)(2)(A)

TXU requested that the commission clarify the meaning of the phrase "plus generation-related asset additions as allowed in the ECOM model filed pursuant to the UCOS rate filing package." Reliant argued that the term "net book value of generation assets" should refer to the categories of asset additions included in the ECOM model and not the dollars allowed for asset additions in the UCOS cases. Reliant also urged that nuclear fuel be listed specifically as part of generation-related assets in this subsection. Reliant recommended that subsection (g)(2)(A) be rewritten accordingly. In addition, Reliant stated that the term "accumulated depreciation" in this subsection is prior to any mitigation.

The commission agrees with TXU that the phrase "plus generation-related asset additions as allowed in the ECOM model filed pursuant to the unbundled cost of service (UCOS) rate filing package" is unclear and has deleted it. The commission also agrees with Reliant that fuel inventories are appropriately included in this subparagraph and has modified the rule accordingly. Additionally, the commission agrees with Reliant regarding the term "accumulated depreciation" and adopts Reliant's suggested revision.

§25.263(g)(2)(A)(i)

TXU noted that if the net mitigation, as defined in subsection (c)(3), has already been applied by the utility to reducing the original cost of generating assets, subsection (g)(2)(A)(i) would double count these mitigation amounts. Accordingly, TXU recommended adding language to clarify that the net book value should be reduced by net mitigation, to the extent such net mitigation has not already served to reduce the net book value of generation assets.

The commission has clarified the potential confusion concerning net book value in its revision to §25.263(g)(2)(A) as described above.

§25.263(g)(2)(A)(iii)

TIEC proposed that this paragraph be deleted as unnecessary because the commission has not authorized any interim competition transition charges (CTCs). TXU recommended that the commission not adopt TIEC's recommendation to delete provisions of the proposed rule concerning reducing the book value of generation-related invested capital that is recovered through any CTC. TXU argued that this provision of the proposed rule is warranted given potential changes in the orders in the UCOS cases and the results of judicial appeals.

The commission agrees with TXU, and this subsection of the rule is adopted without changes to the subsection as proposed.

§25.263(g)(2)(B)

TXU proposed that the heading of this subsection be revised to match the definition of "existing purchased power contracts" under PURA §39.251(2). The definition of "existing purchased power contracts" in this section of PURA includes "any amendments and revisions to that contract resulting from litigation initiated before January 1, 1999." Reliant believes that the rule should use the language of the applicable statutes whenever possible.

The commission agrees and has made the requested change.

§25.263(g)(2)(B)(i)

TNMP indicated that subsection (g)(2)(B)(i) as proposed could be interpreted to require an actual sale, and argues that PURA §39.251(5) is not that restrictive. TIEC replied to TNMP that any market valuation of purchased power contracts in the true-up proceedings should be based on legitimate market offers that result in consummated power transactions. TIEC argued that a transaction involving a purchased power contract could not be considered "bona fide" unless it involves an actual sale of power. TIEC also argued that if potential parties to such a transaction believe that it may not be consummated, they may not participate in bidding for the rights to the contract, or they may not submit legitimate offers.

The commission agrees with TIEC. The wording in PURA §39.251(5), which states that purchased power market value means the value of demand and energy bought and sold in a bona fide third-party transaction, indicates that such transactions must involve an actual sale of power. Accordingly, the commission makes no change to the rule.

§25.263(g)(2)(C)

TIEC proposed that this paragraph be clarified to limit these generation-related regulatory assets only to those assets that have not been securitized.

The commission agrees, and adopts TIEC's proposal to specifically exclude securitized assets.

§25.263(g)(2)(D)

TIEC stated that cost recovery is strictly limited to capital costs, and consistent with §25.261(d)(4), relating to Stranded Cost Recovery of Environmental Cleanup Costs, does not include any operation and maintenance costs. TIEC also argued that this subsection of the rule should specify that the capital costs to improve air quality must have actually been spent before May 1, 2003 to qualify for inclusion in the book value of the utility's generating assets. Reliant and TXU replied that Substantive Rule §25.261 states that an "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." Reliant stated that this is the definition that should be used in the present rule.

The commission agrees with Reliant. Funds need not have been actually expended to be eligible for stranded cost recovery, provided the requirements of Substantive Rule §25.261 have been met. No change was made in response to this comment.

§25.263(g)(2)(E)

AEP, TXU, and Reliant opposed the concept that the commission is permitted to adjust the net book value of a utility's generation assets to reflect a lack of compliance with the utility's obligation to mitigate stranded costs. These utilities generally argued that this aspect of the rule should be deleted because it is contrary to the market-based stranded cost valuation required by PURA.

OPC, TIEC, and ARM replied that PURA §39.252(d) specifically requires the commission to consider a utility's mitigation efforts in determining the amount of a utility's stranded costs. TIEC argued that adjustments to the net book value of the utility's generation assets are a logical means of complying with this statutory mandate. TIEC stressed that the proposed rule provides customers with protections to prevent excessive stranded cost payments that would limit competitive headroom beyond 2004. In addition, TIEC maintained that because any such adjustments would be applied to the book value rather than the market value of the utility's generation assets, the stranded cost mitigation provisions of the commission's published rule in no way interfere with the methods specified by PURA for determining the market value of the utility's assets.

The commission agrees with OPC, TIEC, and ARM that appropriate adjustments can be made to book value in determining ECOM because adjustments to the market value component of the equation are prohibited by PURA. No change to the rule has been made.

§25.263(h)—True-up of final fuel balance

TNMP stated that the term "final fuel balance" seems to reference different final fuel balances. TNMP recommended that the commission define final fuel balance as the final fuel balance determined under PURA §39.202(c). TNMP commented that if this term is defined as suggested, the last phrase of §25.263(h)(3) should delete the wording "calculated pursuant to this section," and §25.263(h)(4) should be modified to state: "the final fuel balance, as adjusted by subsection (*sic*) §25.263(h)(2)-(3) of this rule, shall include carrying costs on the positive or negative fuel balance…." TNMP also suggested that the last phrase of §25.263(h)(3) should be modified to state that, "… the surcharged utility shall add the amount of surcharges and any associated carrying costs paid after 2001 to its final fuel balance" to ensure that the amount a surcharged utility adds to its final fuel balance includes any carrying costs associated with the surcharge.

The commission finds that the recommendation of TNMP to define the final fuel balance as that determined under PURA §39.202(c) is unnecessary, as similar language to TNMP's suggestion appears in §25.263(h)(1). However, the commission agrees that TNMP's suggested modifications to §25.263(h)(3) and (4) provide clarity, and has modified the rule accordingly.

AEP argued that the language of this provision was overly broad. AEP stated that the only fuel surcharge collections that can properly be used to offset the final fuel balance are those that relate to the reconciliation period covered by the final fuel reconciliation. Any fuel surcharges that relate to a reconciliation period prior to that encompassed in the final fuel balance should not be used to reduce the final fuel balance because these surcharge collections have nothing to do with the reconcilable fuel costs at issue in the final fuel reconciliation.

The commission agrees and has made the requested change.

TIEC stated that it appears that §25.263(h)(2) and (3) are unnecessary because the commission has deferred collection of fuel under-recoveries until the final fuel reconciliations.

The commission agrees that it is unlikely that there will be any fuel surcharges imposed after the start of retail customer choice. However, that possibility cannot be foreclosed and this provision is therefore appropriate.

Reliant commented that in regard to §25.263(h)(4), all elements of the true-up should provide that the TDU be allowed to recover, or be liable for, carrying costs from the date that is 150 days after January 12, 2004 until fully recovered by the TDU or by the TDU's customers. As such, Reliant recommended changes to subsections (h)(4) and (l)(3) of the proposed rule. These changes are included in the discussion under Subsection (l)(3).

AEP stated that if the approach contemplated by §25.263(h) results in an extended period for recovery of an under-recovered fuel balance (longer than the one-year recovery period contemplated by the fuel rule), then the short term, debt-like interest rate provided by the fuel rule is inadequate, and interest should be calculated at the weighted-average cost of capital. In contrast, TIEC stated that it is important that the carrying charges associated with the final fuel balances be set at the levels traditionally imposed under §25.236(e), relating to Recovery of Fuel Costs. TIEC supported the proposed rule's imposition of carrying charges consistent with §25.236(e).

The commission agrees with AEP, and has changed the rule such that for recovery periods of one year or less, carrying costs on fuel balances will be at the interest rate determined by the fuel rule, and for periods exceeding one year, carrying costs will be computed using the utility's weighted-average cost of capital determined in its UCOS proceeding.

Subsection (i)—True-up of Capacity Auction Proceeds

"Load-shaping" issues

AEP suggested that the rule must recognize the fact that the capacity auction products cannot be directly entered into the ECOM model without further aggregation of the market price data, as the model was not designed to utilize capacity auction product market price data. That is, the market price must be adjusted to reflect the actual characteristics of the generating capacity used to support the capacity auction, especially firmness (discussed below), because the capacity auction rule assumes no forced outages, and also environmental standards, because the utility must comply with them in dispatching its power units. AEP also pointed out the proposed rule's reliance upon the use of average capacity auction market prices rather than product-specific market prices, with the possible result of stranded incremental fuel costs incurred in connection with the provision of energy associated with the capacity auction products. AEP believes that the use of average market prices could result in an estimate of an APGC's total market-based revenues that differs substantially from the revenues the APGC would actually earn in the marketplace.

Similarly, TIEC stated that the capacity auction true-up mechanism in the proposed rule should be modified to properly compare those prices with the ECOM market prices. TIEC opined that capacity auction prices are wholesale prices and ECOM prices are retail prices so the proper mix of capacity auction products that matches the respective load shape of each customer class must be selected.

Reliant stated that there are four products in the capacity auction: one is a baseload product consisting of nuclear, coal and lignite units, and the other three all represent gas units. The capacity auction will therefore provide one power price for nuclear, coal and lignite generation, and another price for gas generation from the other three products.

TXU disagreed with TIEC's recommendation that the capacity auction prices be modified because capacity auction prices are wholesale prices and the market prices in the ECOM model reflect retail prices. TXU expressed its view that TIEC's recommendation may result from confusion about the terminology associated with the ECOM model. While the ECOM model results represent retail stranded costs, that distinction does not imply that the market prices used in the model are retail but rather reflects the fact that the ECOM model predicts stranded costs associated with generation for retail customers.

AEP replied that TIEC's proposal that the capacity auction price should be "load-shaped" is off base because its intent is not to determine the price ultimately to be paid by a particular customer.

Reliant responded to TIEC's comment regarding Preamble Question #1 that "since the capacity auction prices are wholesale prices and the market prices in the ECOM model reflect retail prices, the proper mix of capacity auction products that matches the respective load shape of each of the three customer classes represented in the ECOM model market prices—residential, commercial and industrial—must be selected." In response to similar comments from OPC in the public hearing on July 25, 2001, Reliant stated that the ECOM model is a wholesale model, not a retail model. Reliant argued that if the model were a retail model, it would also include costs necessary to provide retail service (e.g., marketing costs), but it does not.

The commission finds that the alternative method it has adopted—using aggregated data to calculate the capacity auction true-up without the use of the ECOM model—obviates concerns about "load-shaping." By using total, aggregated capacity auction revenues and actual sales amounts and fuel costs, a simple comparison can be made to the total contribution to fixed costs as estimated in the ECOM model. Therefore, other than changes already discussed with regard to Preamble Question #1, no further modification to the rule is required.

Timing issues related to the capacity auction true-up

TXU commented that although subsection (i)(1) of the rule states that one of the purposes of the proposed rule is to make a final reconciliation of the monthly capacity auction true-up adjustment amounts, neither the proposed rule nor §25.381 of this title, relating to Capacity Auctions, addresses how the monthly amounts are calculated.

TXU noted that the time period provided in §25.381(h)(1), which states that the calculation is performed monthly through the month following the issuance of a final appealable order in the true-up proceeding, does not match the time period proposed in subsection (i)(2), which states that the calculation is performed "for 2002 and 2003." TXU also requested that the rule clarify the time period for calculating the capacity auction total price of power, which the APGC is required to substitute for the projected ECOM market prices. TXU suggested that the capacity auction prices for the one-year strips would be appropriate. TXU also claimed that substituting actual 2002 and 2003 fuel expenses into the ECOM model may be cumbersome, as figures for 2003 will not be available until late January 2004. TXU pointed out that this timing could make it impossible to prepare a true-up application for filing before March or April of 2004. TXU stated that if actual 2003 data were required, depending upon how the requirements of §25.381(h)(1) are reconciled, the utility could supplement its filing as data become available.

Reliant agreed with TXU's observation regarding the mismatch that exists between the time period associated with the true-up of capacity auction proceeds as proposed in subsection (i)(2) and as exists in §25.381(h)(1). Proposed subsection (i)(2) states that the calculation should be performed "for 2002 and 2003" whereas the capacity auction rule requires a monthly calculation beginning February 1, 2002 through the month following the date a final order is issued in the true-up proceeding. Reliant proposed that §25.381(h)(1) be amended to conform to the true-up rule, which defines the true-up period as 2002-2003.

However, Reliant disagreed with TXU's comments that the timing of 2003 fuel expenses may make it impossible to file a true-up application until March or April 2004. Reliant disagrees that the delay contemplated by TXU will be necessary. Reliant stated it would make a special effort to make its fuel cost information available by January 12, 2004. As Reliant explained in its initial comments, it is very important to Reliant that it files its true-up application on January 12, 2004 because of commitments memorialized in its business separation plan.

With regard to the issue of monthly reconciliations, the commission will amend, as proposed by Reliant, §25.381(h)(1) to comply with this section. With regard to the availability of 2003 information in early 2004, the commission believes that the staggered schedule by which companies will file their true-up applications will allow adequate time for the collection of 2003 data. To the extent that precise data is unavailable by the time a company files its true-up application, the company can re-file the updated information as it becomes available and an adjustment to the company's rates can be made.

Applicability of the capacity auction true-up provision

TIEC stated that the difference between two negative ECOM numbers may result in an inequitable positive true-up adjustment, and that such positive adjustment would be collected from customers. TIEC further stated that because customers will not refund any amount prior to 2004, any collection of a positive capacity-auction true-up adjustment during the 2002-2003 time frame is inequitable. To rectify this, the word "any" should be removed from paragraph (1) and clarification should be made that the capacity auction true-up should apply only if the revised ECOM model produces a positive result *and* the commission-approved ECOM is no less than zero.

AEP replied that TIEC's argument that there should be no calculation of the capacity auction/ECOM price true-up unless the utility's ECOM estimate and final stranded cost balance are negative is not supported by PURA §39.262. PURA does not contemplate a refund of negative stranded costs so the results of the true-up process cannot lawfully be a stranded cost balance below zero. In any event, the capacity auction/ECOM price true-up is a stranded cost recovery tool and TIEC's concerns that a utility may realize a windfall are unfounded.

Reliant also disagreed with TIEC's comments on subsection (i) regarding the proposed rule's authorization of the true-up of "any difference between the capacity auction total price of power and the power cost projections for the same time period as used in the determination of ECOM for each utility in the proceeding under PURA §39.201." In response to TIEC claims that the word "any" should be stricken from the proposed rule because it purportedly would create an inequitable result in the true-up, Reliant replied that PURA §39.262(d)(2) expressly refers to "any difference" between the price of power obtained through the capacity auctions and the power cost projections that were employed for the same time period in the ECOM model. Reliant replied that the commission should not reject statutory language.

Reliant also disagreed with TIEC's proposed remedy involving "clarifying that the capacity auction true-up should apply only if the revised ECOM model produces a positive result *and* the commission-approved ECOM is no less than zero." Reliant stated that if by "commission approved ECOM" TIEC means the ECOM result approved by the commission in the UCOS cases, the result of this proposed revision would be to ensure that neither Reliant, TXU, or Central Power and Light Company (CPL) could recover any amounts in the capacity auction true-up, because all of those utilities' approved ECOM amounts were negative. It would also ensure that those utilities owed no money in the capacity auction true-up, even if the capacity auction prices exceed the ECOM market prices. Reliant stated that, in fact, the statute does not contain the limitation proposed by TIEC; it requires a true-up regardless of the results of the UCOS ECOM model run. Reliant stated that TIEC's proposal is contrary to the statute and should be rejected.

TXU objected to TIEC's recommendation that this subsection should be clarified to reflect that the capacity auction true-up would only apply if the revised ECOM model produces a positive result and the commission-approved ECOM is no less than zero. TIEC's concern was that if the commission-approved ECOM was negative and the revised ECOM was also negative, then the difference between these two figures could be a positive number that ratepayers would have to return to the utilities. TXU argued that TIEC's recommendation was unfair because (1) its ECOM was initially under-valued by the commission, and (2) using the artificially low estimate of ECOM would deny TXU the possibility of receiving all that it may be owed under the wholesale clawback if TIEC's recommendation were adopted.

Reliant also disagreed with TIEC's claim that "ratepayers will not receive any refund prior to 2004." In the UCOS cases the commission ruled that utilities must credit nonbypassable charges to reflect an "excess mitigation credit." Even though the credits are paid to REPs rather than being paid directly to ratepayers, the utilities nevertheless are refunding amounts, and those amounts are available to be paid to ratepayers if the REPs choose to do so. Reliant replied that it is therefore inappropriate for TIEC to suggest that utilities will be refunding no amounts before 2004.

TIEC's argument concerning the potential complications of computing the difference between two ECOM numbers pursuant to the capacity auction true-up adjustment is rendered moot by the commission's changes to subsection (i) of the rule, as indicated previously in the discussion regarding Preamble Question #1. Notwithstanding this fact, however, the commission disagrees with TIEC's assertion that no calculation of the capacity auction/ECOM price true-up is necessary unless the utility's ECOM estimate and final stranded cost balance are positive. As subsection (l) of the rule prescribes, the final true-up balance will reflect the netting of several items, including the capacity auction true-up. Even if the capacity auction true-up is positive, it will ultimately be collected from customers only if the netting results in a positive amount. Additionally, the commission agrees that certain utilities are refunding a portion of the negative ECOM amounts determined in the UCOS cases in the form of excess mitigation credits. In any event, the changes to subsection (i) of the rule eliminate the monthly crediting or billing by the APGC to the TDU during the years 2002 and 2003. Therefore, no change to the rule has been made with regard to this issue.

"Firmness" issue

Reliant and AEP stated that the rule should account for additional costs made necessary by capacity auction firmness obligations. In §25.381 of this title, the commission required that capacity auction products be sold as firm products. Reliant and AEP averred that even though the slices of system underlying the capacity auction entitlements are not actually firm, the entitlements themselves must be. Reliant opined that this firmness obligation imparts to the capacity auction products greater value than the underlying units actually possess, and the unit-contingent power that Reliant sells outside the capacity auction will reflect the reduced value.

Reliant and AEP argued that because the capacity auction products are firm, the uncertainty associated with outages during periods of capacity shortages has been shifted from the entitlement holder to the APGC. An APGC would therefore find it necessary to purchase insurance or additional power to satisfy its capacity auction obligations. Thus, Reliant and AEP suggested that if abnormal capacity shortages occur, an APGC should have the opportunity to apply to the commission for relief and to obtain an adjustment upon a showing that the capacity auction revenues do not reflect the true value of the assets. Reliant proposed language reflecting these suggestions.

Cities replied that the claims of Reliant and AEP are disingenuous because it is not apparent how a product intended to represent a slice of the system that provides firm service can be more firm than the system itself. Cities claimed that the capacity calls of the auction were actually inferior to the entire system.

OPC argued that stranded costs will be overestimated if the auctioned entitlements have less value than the power historically sold by the utilities. OPC suggested that this will occur because the power cost projections that were employed for the same time period in the ECOM model are based on historical operation, not on the estimated cost of delivering power to holders of capacity auction entitlements. OPC noted that, if anything, comparing the value of the call options on wholesale power sold in the capacity auctions will overestimate ECOM, and therefore no adjustments should be made to the value of the capacity auction entitlements that would act to further overestimate ECOM.

In response to AEP, OPC claimed that the need for firmness issues in the capacity entitlements was fully discussed during the capacity auction rulemaking and should not be revisited.

In reply to OPC's comments that the capacity auction true-up should contain no adjustment for firmness, Reliant argued that the true-up of the capacity auction products is not to a full-requirements product; rather, the true-up is to the APGC's generation assets. Reliant claimed that OPC's argument is therefore wrong, and the APGC should have the opportunity during the true-up to establish the need for a firmness adjustment.

The commission finds that the issue of firmness was sufficiently debated in the capacity auction rule. In that rule, the commission determined the capacity auction products to be reasonable and reflective of wholesale market products. Reliant's proposed language could conceivably create incentives for affiliated REPs to incur additional costs that may not be necessary given the surplus of capacity in Texas. Accordingly, no provision has been included in the rule to allow for an adjustment related to the firmness of the capacity auction products.

Alternatives to the ECOM model

Reliant proposed two solutions for calculating the capacity auction true-up with the use of the ECOM model. For the first alternative, Reliant proposed that actual values be used for gas-fired generation revenues and gas-fired generation sales. Reliant stated, however, that even if the inputs to the ECOM model are so revised, a concern remains that the "Plant Economics" sheet of the model will make an inappropriate economic adjustment. In order to avoid an economic adjustment in the model, the price of power must exceed not only the fuel variable costs, but also other variable additional costs (such as plant operators, maintenance personnel, property taxes, and depreciation expenses associated with incremental capital costs) that are not variable in the short run. However, because retirements are largely irreversible (i.e., it is impractical and very costly to retire a plant in one year and bring it back the next), in reality the decision is not based upon costs and revenues in a single year. If an owner does not expect to cover costs in a given year, but expects to make a profit in subsequent years, then it would not make sense to retire the plant. In a competitive market with fluctuating prices, it is unlikely that a plant owner will cover all costs of all plants in each and every year. Furthermore, the 15% capacity auction entitlements for 2002 and part of 2003 have been established based on APGCs' existing plant fleets. If the APGC is forced to shut down a plant to avoid an ECOM economic adjustment, the APGC will effectively be required to auction in excess of the 15%. Reliant commented that it is unfair to punish the APGC after the fact. Consequently, Reliant stated that the economic adjustment in the ECOM model would effectively disallow non-fuel operations and maintenance expenses under certain circumstances. Reliant therefore recommended that the APGC be provided an opportunity to challenge an economic adjustment it believes is inappropriate, and included suggested language to allow for that opportunity, assuming the capacity auction true-up remained within the context of the ECOM model.

The other method that Reliant proposed would freeze the economic adjustment amount at the level that appeared in the PURA §39.201 proceeding. Although this methodology modifies the ECOM model to some extent, Reliant believes it is entirely consistent with the purpose of the economic adjustment in the model. An entitlement owner will not exercise its option to purchase gas-based generation unless the entitlement can provide power cheaper than the alternative, which is the market price of power. If the market price is cheaper, the entitlement owner will instead go to the market to purchase the power. Thus, by definition, any time an APGC sells a gas-based generation product in the capacity auction, the cost of that product is lower than the market price and the economic adjustment should not disallow costs. Reliant offered revised language reflecting these suggestions.

The commission finds that the alternative method it has adopted—using aggregated data to calculate the capacity auction true-up without the use of the ECOM model—avoids concerns regarding the "Plant economics" adjustment in the model. Therefore, other than changes already discussed, no further modification to the rule is required.

Use of company-specific results from capacity auction

TIEC commented that the capacity auction prices used in each utility's reconciliation should be based on its specific capacity auction. TXU supported TIEC's recommendation that the rule specify that capacity auction prices used in each utility's price reconciliation should be based on results of that utility's capacity auction. TXU requested that the rule incorporate TIEC's recommendation.

AEP stated that §25.381(d) of the commission's capacity auction rule contemplated that divestiture of generating capacity would satisfy the capacity auction obligation under specified circumstances. Because CPL was subject to the requirement that it divest three of its generation facilities under the commission's order approving the merger between AEP and Central & South West Corporation, this provision was applicable to CPL. Once accomplished, the divestiture required by the merger approval order that will exceed 15% of CPL's generating capacity will fulfill CPL's capacity auction requirement. As a result of the divestiture, CPL would no longer have actual capacity auction prices that could be used in determining its ECOM/capacity auction true-up. By the time of the 2004 true-up, however, there will be ample information from numerous sources on prevailing capacity auction prices that would enable CPL to determine reasonable capacity auction prices for purposes of its own true-up calculation. Hence, CPL requested that it be allowed to propose in its true-up filing a methodology for arriving at an ECOM/capacity auction true-up that reflects it unique circumstances.

The commission agrees that, where possible, company-specific capacity auction prices should be used in companies' true-up applications. If a company has unique circumstances that result in its having no company-specific capacity auction data, the company may request in its true-up application a method using data from prevailing capacity auction prices to determine an appropriate surrogate to be used in its own capacity auction true-up. The rule has been changed to accommodate these situations.

§25.263(j)—True-up of price to beat revenues

§25.263(j)(2)

TXU and TNMP expressed concerns related to the timing of the determination of market price for the purposes of the retail clawback. These concerns and the commission responses are addressed under Preamble Question #3 and subsection (c), relating to Definitions.

§25.263(j)(5)(A)

ARM recommended adding language to subsection (j)(5)(A) to provide that residential and small commercial customers being served by the AREP as a POLR outside its affiliated TDU area not be counted in this calculation. ARM explained that customers served by the AREP as a competitor outside of its affiliated TDU area are subtracted from the customers it serves under the PTB in its affiliated TDU area in order to calculate the retail clawback. ARM emphasized that POLR service is not—and is not intended to be—a competitive service. ARM said that if customers served by the AREP as a POLR are included, it would contravene the intent of the Legislature to encourage AREPs to compete in other areas. ARM suggested that it would also encourage AREPs to game the POLR RFP, by under-bidding other non-affiliated REPs to reduce their exposure to the retail clawback. ARM claimed that the commission decided a similar issue in the PTB rulemaking, and excluded customers dropped to the POLR for the calculation of the 40% threshold for customer switches for §25.41(i).

The commission agrees that customers served by the POLR should not be counted in determining the number of customers served by an AREP outside the region of its affiliated TDU because POLR service is not considered to be a competitive retail option. The rule has been changed in accordance with the recommendation of ARM.

§25.263(k)—Regulatory assets

According to AEP, situations may arise in which regulatory assets are included in a financing order, but are ultimately not subject to securitization. These regulatory assets should be included in the true-up balance to avoid understatement of that balance. In its Order Number 14 in Docket Number 22344, the commission anticipated that such an adjustment could be required as part of the true-up proceeding.

Reliant commented that subsection (k) of the proposed rule reflects only the provisions of PURA §39.262(f). AEP recommended that additional language be added to this subsection to recognize that regulatory assets included in a financing order but ultimately not subject to securitization should be included in the TDU/APGC true-up balance under subsection (l). Reliant agreed with AEP's proposed additional language. Reliant also believes that the language can be added either to subsection (k) or included elsewhere in the true-up rule.

The commission agrees with AEP and Reliant, and incorporates AEP's suggested language in the rule.

§25.263(l)—TDU/APGC true-up balance

§25.263(l)(1)

TIEC, ARM, OPC, and Cities commented that the netting of the final fuel reconciliation balance with other items of the stranded cost true-up is the correct interpretation of PURA §39.262, is not prohibited by PURA, and is consistent with the commission's explicit intent as evidenced by the deferral of the disposition of fuel under-recoveries to the true-up. TXU, Reliant, and AEP argued that PURA §39.201(l) and §39.262(g) are two separate but parallel true-up proceedings. These parties generally commented that it is inappropriate and contrary to PURA to net the final fuel reconciliation balance and capacity auction/ECOM reconciliation against other elements of the stranded cost determination and that §39.262(c) and (d) provide for different dispositions of these elements of the true-up.

The commission believes that the overriding factor in implementing PURA §39.262 is the requirement that a utility not be permitted to over-recover its stranded costs. PURA §39.262 establishes the process for conducting the final true-up. As part of the true-up, stranded costs are finalized, the wholesale and retail clawbacks are calculated, fuel costs are reconciled for a final time, and regulatory asset amounts are adjusted. At the conclusion of this process, nonbypassable charges are adjusted. PURA §39.201(g)-(h) sets out the process for calculating stranded costs and mechanisms for adjusting an excessive CTC. These include reducing the CTC, reversing redirected depreciation, reducing TDU rates, or a combination of any of these mechanisms. PURA §39.262 provides for further adjustments to one or more of these items. Thus, §39.262 calls for similar adjustments to nonbypassable charges to reflect the difference in projected and actual stranded costs, the retail and wholesale clawbacks, final fuel balance, and regulatory assets.

All the true-up items result in adjustments to the nonbypassable charges. It is therefore reasonable to assume that these adjustment items should be netted against one another prior to making adjustments to the nonbypassable charges. The statute does not require the commission to make successive adjustments to the nonbypassable charges for each of these items. The commission concludes that it is appropriate to net each of the true-up components because stranded costs may be over-recovered in violation of PURA if these items are not netted.

For example, consider a utility whose final determination of stranded costs under PURA §39.262(h) and (i) is negative $2 billion, but whose capacity auction true-up adjustment is a positive $100 million. If the capacity auction adjustment is not netted against stranded costs, the TDU will owe its APGC $100 million, because the negative $2 billion is considered to be $0 and the capacity auction adjustment of $100 million is then added to the $0 amount of stranded costs. On the other hand, if the capacity auction adjustment is netted against stranded costs, the amount owed to the APGC by the TDU, and vice versa, is $0. In the first example, over-recovery of stranded costs would occur because the utility would recover $100 million, even though its net stranded costs were negative $1.9 billion. Moreover, with regard to PURA §39.262(f), netting of regulatory asset amounts against stranded costs is the only reasonable approach to handling credits. If a utility has negative $500 million in stranded costs as determined under PURA §39.262(h) or (i), but the commission has denied regulatory asset treatment for $100 million of the utility's regulatory assets, it would not be appropriate to zero out the negative $500 million stranded cost amount and then credit ratepayers $100 million dollars. The $100 million should simply be netted against the negative $500 million amount, resulting in a negative $400 million amount, none of which would be returned to customers.

§25.263(l)(2)(A)

TNMP commented that the phrase "and greater than projected stranded costs" is not clear as to whether it means a projection of stranded costs as determined by the commission in various dockets resolved in 2001 or to stranded costs estimated in the 1998 report to the legislature. TNMP suggested that the commission clarify this point.

The term "projected stranded costs" is clearly defined in proposed §25.263(c)(5) of this section to mean the projected stranded costs as determined by the commission in the 2001 dockets and does not require further clarification.

§25.263(l)(2)(B)

TIEC commented that because stranded costs originally projected were uniformly negative, it appears that a positive true-up balance could never be less than a utility's projected stranded cost amount from the UCOS case so that this section would not be applicable to any Texas utility.

Because of the possibility that the final orders in the UCOS cases will not be issued prior to adoption of this rule, and consequently appeals to the courts will remain unresolved prior to adoption, this section should remain in the rule as proposed.

§25.263(l)(2)(C)(ii)

AEP noted that the commission had previously recognized the option of applying excess earnings to capital expenditures to improve or expand transmission and distribution (T&D) facilities or to improve air quality, and believes that these options should be available to utilities in the true-up. In response to AEP's proposal, TIEC argued that none of the methods listed in PURA §39.262 contemplates the use of excess mitigation funds for infrastructure or air quality projects and maintains that the statute envisions that any such balances owed to customers would be returned to them through mechanisms such as rate reductions. ARM and OPC voiced similar objections to this proposal.

Additionally, Reliant commented that the reference to the APGC in the sentence reading "mitigation reversed shall be returned to ratepayers by the APGC through an excess mitigation credit" (emphasis added) should be changed to the TDU because it is the TDU that will return amounts to ratepayers through changes to its nonbypassable charges.

The commission does not believe that the statute contemplates the option of using stranded costs as determined under PURA §39.262 for infrastructure improvements or air quality projects. This option was only available to non-stranded cost utilities with respect to excess earnings during the transition period ending December 31, 2001. The change from APGC to

TDU proposed by Reliant is not necessary. It is understood that any reversal of excess mitigation by the APGC will be flowed through the TDU to ratepayers.

§25.263(l)(2)(C)(iii)

TIEC and ARM commented that the imposition of a negative CTC to return negative true-up balances to customers is appropriate because customers have borne all the costs associated with a utility's generation assets. They generally argued that if no negative CTC is allowed, the commission would be imposing asymmetric risks and rewards on the utility's shareholders and customers. Additionally, ARM stated that it is "right and just" that a negative CTC be implemented and believes that the commission is fully empowered by PURA to do so. Cities also argued that it is equitable to impose a negative CTC.

TIEC did not support the proposal to cap the negative CTC at the amount of securitized assets included in a utility's transition charges. According to TIEC's comments, such a cap would have the unjustifiable result of limiting negative CTC exposure to some utilities and not others because, under the proposed rule, a utility that has not securitized any stranded costs would be required to return the full amount of any negative true-up balance to customers while utilities with TCs may not be required to return all such negative balances.

Reliant and AEP commented that, while the legislature has expressly provided for the recovery of stranded costs (*see* PURA §39.001(b)(2) and §39.252(a)), it has clearly rejected the concept of "negative stranded costs" in each of the last two legislative sessions. Additionally, TXU and TNMP argued that the commission has no authority to establish a negative CTC and recommended deleting this section. Reliant also stated that TIEC is confused in its arguments against the "cap" in proposed Subsection (l)(2)(C)(iii). According to Reliant, contrary to what TIEC argued, the proposed cap would eliminate the possibility of a negative CTC for a utility that has not securitized regulatory assets or stranded costs because the cap would be based on "the lesser of the absolute value of the remaining negative true-up balance or the securitization amount on which any TCs are based."

The commission does not agree that a negative CTC is prohibited if a utility having negative stranded costs has securitized regulatory assets that are being recovered from ratepayers through a TC. This is consistent with the previously stated position that the overriding factor in implementing PURA §39.262 is the requirement that a utility not be permitted to over-recover its stranded costs. With respect to subsection (l)(2)(C)(iii), the commission intended that a negative CTC be imposed to the extent that negative stranded costs were available to offset a positive TC. Though the commission does not agree with TIEC that the proposed rule limits negative CTC exposure for some utilities and not others, it has nonetheless revised subsection (l)(2)(C)(iii) to clarify that no negative CTC will be imposed if the utility has not securitized regulatory assets.

§25.263(l)(2)(D)

TXU commented that it is not clear that §25.263(l)(2)(D), which provides for a CTC to collect any positive fuel balance, differs from §25.263(l)(2)(A) and (B), both of which allow securitization of positive balances. TXU stated that PURA Chapter 39, Subchapter G, is only for regulatory assets and stranded costs and does not apply to anything else. AEP commented that this section establishes a separate mechanism to ensure that a utility returns any over-recovered fuel balance to customers, even in the event of an overall negative true-up balance. AEP argued that if the final fuel balance is included as a component of one overall true-up balance, then the rule should include a parallel provision requiring that a fuel surcharge shall be implemented to recover the under-recovered fuel balance from ratepayers, without regard to whether the APGC has an overall negative stranded cost balance. AEP believes that fuel cost reconciliation and recovery should be a two-way street in the true-up process, and should result in making both customers and utilities whole.

Pursuant to the instructions in §25.263(l)(2) and §25.263(d)(3), §25.263(l)(2)(D) applies to utilities that were not reported to have stranded costs in the April 1998 Report to the Texas Legislature. Accordingly, the option to securitize a positive balance is not available to these utilities. Additionally, because it does apply only to the non-stranded costs companies, this provision is necessary to ensure that fuel over-recoveries are properly returned to ratepayers.

§25.263(l)(3)

Reliant noted that proposed subsection (l)(3) provides for carrying costs on both positive and negative true-up balances, but only from the date of the final true-up order forward. Proposed subsection (d)(1) states that the commission will establish a schedule to set forth when each utility will file its true-up application. Reliant commented that, presumably, the commission will use a staggered filing schedule. Therefore the final orders for each TDU will be issued on different dates, perhaps months apart. Reliant believes that it is unfair to have interest accrue to the ratepayers or TDUs at different dates depending on the filing schedule, and that all elements of the true-up should therefore provide that the TDU be allowed to recover, or be liable for, carrying costs from the date that is 150 days after January 12, 2004 until fully recovered by the TDU or by the TDU's customers. Reliant further commented that this change also would necessitate a similar change to proposed subsection (h)(4) to ensure that the carrying charges on fuel change from the rate approved in Substantive Rule §25.236, relating to Recovery of Fuel Costs, to the utility's cost of capital on the 150th day after January 12, 2004.

In response to Reliant's argument, TIEC replied that the published rule requires each TDU to file an application for a rate adjustment to reflect the results of its true-up proceeding within 60 days of the issuance of a final order in that individual utility's true-up case; therefore, there should be no difference in the carrying charges that will accrue for some utilities versus others simply by operation of a staggered filing schedule for the true-up cases. Moreover, TIEC argued that a utility's true-up balance appropriately becomes due upon the issuance of a final order in that utility's true-up case.

TXU disagreed with the concept of requiring the payment of carrying costs in connection with §25.263(l)(3).

The commission concurs with TIEC that a utility's true-up balance becomes due upon the issuance of a final order in that utility's true-up proceeding and that carrying charges should only accrue from that date forward. The additional change to §25.263(h) proposed by Reliant is therefore not necessary.

§25.263(m)—TDU/AREP true-up balance

Section §25.263(m)

TXU and Reliant proposed that the liability for any carrying costs associated with the PTB clawback should transfer from the AREP to the TDU once the AREP has paid any balance owed to the TDU for the retail clawback. TIEC did not object to this proposal; however, TIEC argued that the final rule should make it clear that *either* the AREP or the TDU will remain responsible for the payment of carrying charges on the true-up balance from the time of the final order in the true-up proceeding until any such balance is fully paid.

TXU argued that the references to carrying costs in the proposed rule should be omitted because they are inappropriate in this instance. TXU claimed that there will be no meaningful lag time between the time of the final order and full recovery of the claw-back amount and, therefore, the affiliated REP should not be liable for any subsequent carrying costs.

The commission disagrees. The retail clawback is a one-way transfer of funds from the AREP to the TDU. It is appropriate for the TDU to recover carrying charges for any period of delayed payment from the AREP. Accordingly, no change to the rule has been made.

§25.263(n)—Rate case subsequent to the true-up proceeding

Section §25.263(n)

Subsection (n) mandates that a TDU "shall file an application to adjust its rates within 60 days following the issuance of a final, appealable order on its true-up proceeding." Reliant, TXU and AEP believe that it is unnecessary to require a full cost-of-service rate case following the true-up. Reliant commented that the legislature has provided the commission with the authority (PURA §39.262(g)) to adjust nonbypassable charges to reflect the results of the true-up, so a rate case is unnecessary. AEP agreed that PURA provides both the utility and other parties adequate recourse to request a full rate case should one become necessary. AEP also supported limiting the post-true-up rate adjustments to those arising from the proceeding.

The commission agrees that a full cost-of-service rate case, per PURA Chapter 36, is not necessary. PURA provides the commission the authority to adjust the TDU's rates without a PURA Chapter 36 proceeding. The commission will determine the details and nature of subsection (n) proceedings at the time of review. The "rate case" language has been removed.

Both TXU and Reliant believe that a separate proceeding to address any rate changes resulting from the true-up proceeding is not contemplated by PURA. TXU and Reliant agreed that the commission should adjust the TDU's rates in the PURA §39.262 true-up proceedings. Reliant also suggested that the TDU be required to file a compliance tariff within 30 days after the final order is issued in the true-up proceeding. For these reasons, TXU and Reliant proposed that subsection (n) be deleted.

TIEC disagreed with the above proposal and stated that injecting potentially controversial cost allocation and rate design issues into the true-up proceedings would unreasonably burden the resources of the commission and intervenors, and hinder the efficient processing of the true-up cases. ARM echoed TIEC's concerns and stated that a true-up case with a statutory time limit of only 150 days is not the appropriate vehicle to consider contested issues of cost allocation and rate design.

The commission disagrees with TXU and Reliant. A separate proceeding will enable the commission to properly address CTC related issues, allocation issues, etc.

Reliant suggested that subsection (n) should state that the TDU can apply for securitization of the amounts due to it at any time after the final order is issued in the true-up proceeding.

PURA Chapter 39 provides for such securitization. Therefore, it is not necessary to include Reliant's suggested language in this rule.

If the commission retains the requirements of subsection (n), TXU requested that all references to the calculation of carrying costs be modified "from the date of a true-up final order" to "from the date of an order implementing the true-up proceeding results in rates."

As discussed above, the commission has removed from subsection (n) the references to changes in rates and, accordingly, has not changed the language in the rule regarding the time period over which carrying costs are calculated.

Other Comments

TXU commented that the sole provision in PURA for adjusting the PTB is found in PURA §39.202(k). TXU argued that the true-up rule should confirm that if adjustments are made to the TDU's nonbypassable charges during the true-up proceeding that reduce headroom, the PTB should be adjusted to restore headroom to the levels set based on the headroom filing required by the PTB rule. TXU further argued that no adjustments to the PTB should be mandated if headroom increases as a result of the true-up because the competitive market will address such a situation.

In adjusting the PTB, the commission will take into account not only the results of the true-up proceeding, but also other factors that increase or decrease the PTB. Consequently, to maintain maximum flexibility in setting the PTB in 2004, the commission declines to include in the true-up rule specific criteria for adjustments to the PTB.

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

This new rule is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2001) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, PURA §39.252 which addresses a utility's right to recover stranded costs and PURA §39.262 which requires the commission to conduct a true-up proceeding for each investor-owned electric utility after the introduction of customer choice.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 39.252 and 39.262

§25.263. True-up Proceeding.

(a) **Purpose.**

(1) The purpose of the true-up proceeding is to quantify and reconcile the amount of stranded costs, the differences in the price of power obtained through the capacity auctions and the power costs used in the excess costs over market (ECOM) model; the results of the annual reports; the level of excess revenues, net of nonbypassable delivery charges, from customers who continue to pay the price to beat (PTB); the reasonable regulatory assets not previously approved in a rate order that are being recovered through competition transition charges (CTCs) or transition charges (TCs); and the final fuel balances. The purpose of the true-up proceeding is also to provide for the recovery of regulatory assets not already approved for securitization that were to be considered in future proceedings pursuant to a commission financing order in a securitization case.

(2) An electric utility, together with its affiliated retail electric provider (AREP), its affiliated power generation company (APGC), and its affiliated transmission and distribution utility (TDU), shall not be permitted to over-recover stranded costs through the application of the measures provided in the Public Utility Regulatory Act (PURA), Chapter 39, or under the procedures established in PURA §39.262 and this section.

(b) **Application.** This section applies to all investor-owned transmission and distribution utilities established pursuant to PURA §39.051, their APGCs, and their AREPs. In addition, the reporting requirements of subsection (j)(6) of this section apply to all retail electric providers (REPs) serving residential and small commercial customers.

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

(1) **Capacity auction total price of power ($/MWh)** — The total (fuel plus non-fuel) capacity auction revenues for entitlements to capacity for the years 2002 and 2003 divided by the total capacity auction energy (expressed in MWh) scheduled to be delivered for those entitlements over the same time period.

(2) **Independent third party** — The party designated by the commission to perform the duties described in subsection (j) of this section.

(3) **Mitigation** — The total excess earnings and redirected depreciation applied to generation assets pursuant to PURA §39.254 and §39.256 or a commission order issued after 1996 that approved a utility's transition case.

(4) **Net mitigation** — Any mitigation that has not been reversed or refunded as of the date of the final order in the true-up proceeding.

(5) **Net value realized** — All compensation paid by a buyer for generation assets, including the buyer's assumption of debt, less any costs of sale such as legal fees, broker fees, and other reasonable transaction costs.

(6) **Projected stranded costs** — The value produced by the ECOM model and approved by the commission in the proceeding conducted pursuant to PURA §39.201.

(7) **Regulatory assets** — The generation-related portion of the Texas jurisdictional portion of the amount reported by the electric utility in its 1998 annual report on Securities and Exchange Commission Form 10-K as regulatory assets and liabilities, offset by the applicable portion of generation-related investment tax credits permitted under the Internal Revenue Code of 1986.

(8) **Residential market price of electricity** — The volume-weighted average price, less average nonbypassable charges (each expressed in cents per kilowatt-hour (kWh)), calculated by the independent third party for residential electric service provided by non-affiliated retail electric providers and non-provider of last resort (POLR) service providers competing in the TDU region. The price determined by the independent third party shall be based upon pricing disclosures pursuant to §25.475(e) of this title (relating to Information Disclosures to Residential and Small Commercial Customers) and other information provided to the independent third party.

(9) **Residential net price to beat** — The average residential PTB rate (expressed in cents per kWh) less the average nonbypassable charges (expressed in cents per kWh) applicable to residential customers.

(10) **Small commercial market price of electricity** — The volume-weighted average price, less average nonbypassable charges (each expressed in cents per kWh), calculated by the independent third party for small commercial electric service provided by non-AREPs and non-POLR service providers competing in the TDU region. The price determined by the independent third party shall be based upon pricing disclosures pursuant to §25.475(e) of this title and other information provided to the independent third party.

(11) **Small commercial net price to beat** — The average small commercial PTB rate (expressed in cents per kWh) less the average nonbypassable charges (expressed in cents per kWh) applicable to small commercial customers.

(12) **Transferee corporation** — A separate affiliated or non-affiliated company to whom an electric utility or its APGC transfers generation assets.

(13) **Transmission and distribution utility (TDU)** — A transmission and distribution utility that, pursuant to PURA §39.051, is the successor in interest of an electric utility certificated to serve an area.

(14) **Transmission and distribution utility region (TDU region)** — The affiliated transmission and distribution utility's service territory.

(d) **Obligation to file a true-up proceeding.**

(1) Each TDU, its APGC, and its AREP shall jointly file after January 12, 2004, on a schedule to be determined by the commission, a true-up application pursuant to subsection (e) of this section.

(2) Each TDU that is a successor in interest of any utility that was reported by the commission to have positive ECOM, denoted as the "base case" for the amount of stranded costs before full retail competition in 2002 with respect to its Texas jurisdiction in the April 1998 Report to the Texas Senate Interim Committee on Electric Utility Restructuring entitled "Potentially Strandable Investment (ECOM) Report: 1998 Update," and such TDU's, APGC's, and AREP's, shall file the true-up application as required by subsections (f) – (k) of this section.

(3) All TDUs not described in paragraph (2) of this subsection, their APGCs, and their AREPs shall file the applications required by subsections (h) and (j) of this section.

(e) **True-up filing procedures.**

(1) Each TDU, APGC, and AREP shall file all testimony and schedules on which they intend to rely for their direct case in accordance with the true-up filing package prescribed by the commission.

(A) Within 20 calendar days of the filing of a true-up application, commission staff or any intervenor may file a motion stating that the filing is materially deficient. Any such motion shall include a detailed explanation of the claimed material deficiencies.

(B) If the presiding officer determines that an application is materially deficient, the TDU, APGC, and AREP shall correct the deficiencies within 30 calendar days. The deadline for final commission order shall be extended day for day from the date of initial filing until the corrections are filed with the commission.

(2) At least 90 days prior to the filing of the first true-up application scheduled by the commission, a utility's APGC shall file a notification of intent with the commission if it intends to utilize PURA §39.262(i) to determine the amount of its stranded costs for nuclear assets.

(3) The commission may initiate a generic proceeding to determine true-up issues that are common to multiple TDUs, APGCs, and AREPs. This proceeding may include updates to the ECOM model required by subsection (f)(2)(B) of this section, in the event a notification of intent is filed pursuant to paragraph (2) of this subsection. The commission may order further updates to any order approved in a generic proceeding pursuant to this section for any utility whose customers are not offered competition on January 1, 2002.

(4) As part of the true-up proceeding, the commission shall make a determination with respect to whether the TDU, the APGC, and the AREP have complied with PURA §39.252(d). If the commission finds that the TDU, the APGC, or

the AREP have failed, individually or in combination, to fully comply with their obligations under PURA §39.252(d), the commission may reduce the net book value of the APGC's generation assets or take other measures it deems appropriate in the true-up proceeding filed under this section. In making a determination as to compliance with PURA §39.252(d), the commission shall not substitute its judgment for a market valuation of generation assets determined under PURA §39.262(h) or (i).

(5) The State Office of Administrative Hearings shall employ expedited procedures during discovery in the true-up proceedings.

(6) The commission shall issue the final order for each proceeding filed under this section not later than the 150th day after the filing of a complete, non-deficient application. Notwithstanding the foregoing, however, the 150-day deadline may be extended by the commission for good cause.

(f) **Quantification of market value of generation assets.**

(1) Market value of generation assets shall be quantified using one or more of the following methods:

(A) **Sale of assets method.** If an electric utility or its APGC sells some or all of its generation assets after December 31, 1999, in a bona fide third-party transaction under a competitive offering, the total net value realized from the sale shall establish the market value of the generation assets sold. Within 30 days of closing, the utility or its APGC shall provide to the commission a detailed explanation, which may be filed confidentially, of the transaction and a description of the generating unit, property boundaries, fuel and parts, emission allowances, and other general categories of items associated with the sale, including any ancillary items related to the assets.

(B) **Stock valuation method.** The following method of market valuation without using a control premium may be used to value generation assets.

(i) If, at any time after December 31, 1999, an electric utility or its APGC has transferred some or all of its generation assets, including, at the election of the electric utility or the APGC, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, not less than 51% of the common stock of each corporation is spun off and sold to public investors through a national stock exchange, and the common stock has been traded for not less than one year, the resulting average daily closing price of the common stock over 30 consecutive trading days chosen by the commission out of the last 120 consecutive trading days before the true-up filing required by this section establishes the market value of the common stock equity in each transferee corporation.

(ii) The average book value of each transferee corporation's debt and preferred stock securities during the 30-day period chosen by the commission to determine the market value of common stock shall be added to the market value of its stock.

(iii) The market value of each transferee corporation's assets that is determined as the sum of clauses (i) and (ii) of this subparagraph shall be reduced by the corresponding net book value of the assets acquired by the transferee corporation from any entity other than the affiliated electric utility or APGC.

(iv) The market value of the assets determined from the procedures required by clauses (i), (ii), and (iii) of this subparagraph establishes the market value of the generation assets transferred by the affiliated electric utility or APGC to each separate corporation.

(C) **Partial stock valuation method.** The following method of market valuation using a control premium may be used to value generation assets.

(i) If, at any time after December 31, 1999, an electric utility or its APGC has transferred some or all of its generation assets, including, at the election of the electric utility or the APGC, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, at least 19%, but less than 51%, of the common stock of each corporation is spun off and sold to public investors through a national stock exchange, and the common stock has been traded for not less than one year, the resulting average daily closing price of the common stock over 30 consecutive trading days chosen by the commission out of the last 120 consecutive trading days before the filing establishes the market value of the common stock equity in each transferee corporation.

(ii) The commission may accept the market valuation to conclusively establish the value of the common stock equity in each transferee corporation or convene a valuation panel of three independent financial experts to determine whether the per-share value of the common stock sold is fairly representative of the per-share value of the total common stock equity or whether a control premium exists for the retained interest.

(iii) Should the commission elect to convene a valuation panel, the panel must consist of financial experts chosen from proposals submitted in response to commission requests from the top ten nationally recognized investment banks with demonstrated experience in the United States electric industry, as indicated by the dollar amount of public offerings of long-term debt and equity of United States investor-owned electric companies over the immediately preceding three years as ranked by the publication "Securities Data" or "Institutional Investor."

(iv) None of the financial experts chosen for the panel shall have participated, or be employed by an investment house or brokerage house which has participated, in the business separation, securitization, or other activities related to the implementation of PURA Chapter 39 on behalf of the utility for which the market valuation is being determined.

(v) If the panel determines that a control premium exists for the retained interest, the panel shall determine the amount of the control premium, and the commission shall adopt the determination, but may not use the control premium to increase the value of the assets by more than 10%.

(vi) The costs and expenses of the panel, as approved by the commission, shall be paid by each transferee corporation.

(vii) The determination of the commission, based on the finding of the panel and other admitted evidence, conclusively establishes the value of the common stock of each transferee corporation.

(viii) The average book value of each transferee corporation's debt and preferred stock securities during the 30-day period chosen by the commission to determine the market value of common stock shall be added to the market value of its stock.

(ix) The market value of each transferee corporation's assets shall be reduced by the corresponding net book value of the assets acquired by the transferee corporation from any entity other than the electric utility or its APGC.

(x) The market value of the assets resulting from the procedures required by clauses (i) - (ix) of this subparagraph establishes the market value of the generation assets transferred by the electric utility or APGC to each transferee corporation.

(D) **Exchange of assets method.** If, at any time after December 31, 1999, an electric utility or its APGC transfers some or all of its generation assets, including any fuel and fuel transportation contracts related to those assets, in a bona fide third-party exchange transaction, the stranded costs related to the transferred assets shall be the difference between the net book value and the market value of the transferred assets at the time of the exchange, taking into account any other consideration received or given.

(i) The market value of the transferred assets may be determined through an appraisal by a nationally recognized independent appraisal firm, if the market value is subject to a market valuation by means of an offer of sale in accordance with this subparagraph.

(ii) To obtain a market valuation by means of an offer of sale, the owner of the asset shall offer it for sale to other parties under procedures that provide broad public notice of the offer and a reasonable opportunity for other parties to bid on the asset. The owner of the asset shall provide to the commission copies of all documentation explaining and attesting to the utility's sale proposal.

(iii) The owner of the asset may establish a reserve price for any offer based on the sum of the appraised value of the asset and the tax impact of selling the asset, as determined by the commission.

(iv) Within 30 days of closing, the utility or its APGC shall provide to the commission a detailed explanation, which may be filed confidentially, of the transaction and a description of the generating unit, property boundaries, fuel and parts, emission allowances, and other general categories of items associated with the transfer, including any ancillary items related to the assets.

(2) **ECOM Method.** Unless an electric utility or its APGC combines all its remaining generation assets into one or more transferee corporations pursuant to paragraph (1)(B) or (C) of this subsection, the electric utility shall quantify its stranded costs for nuclear assets using the ECOM method.

(A) The ECOM method is the estimation model prepared for and described by the commission's April 1998 Report to the Texas Senate Interim Committee on Electric Restructuring entitled "Potentially Strandable Investment (ECOM) Report: 1998 Update." The methodology used in the model must be the same as that used in the 1998 report to determine the "base case."

(B) As part of the filing specified in subsection (d) of this section, the electric utility shall rerun the ECOM model using updated company specific inputs required by the model, updating the market price of electricity, and using updated natural gas price forecasts and the capacity cost based on the long-run marginal cost of the most economic new generation technology then available, as approved by the commission pursuant to subsection (e)(3) of this section. Natural gas price projections used in the model shall be forward prices of Houston Ship Channel natural gas.

(C) Growth rates in generating plant operations and maintenance costs and allocated administrative and general costs shall be benchmarked by comparing those costs to the best available information on cost trends for comparable generating plants.

(D) Capital additions shall be benchmarked using the 1.5% limitation set forth in PURA §39.259(b).

(g) **Quantification of net book value of generation assets.**

(1) For purposes of this section, the net book value of generation assets shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under subsection (f) of this section, whichever is earlier.

(2) Net book value of generation assets consists of:

(A) The generation-related electric plant in service, less accumulated depreciation (exclusive of depreciation related to mitigation), plus generation-related construction work in progress, plant held for future use, and nuclear, coal, and lignite fuel inventories, reduced by:

(i) net mitigation;

(ii) the net book value of nuclear generation assets if quantification of ECOM related to those nuclear generation assets is determined pursuant to PURA §39.262(i); and

(iii) any generation-related invested capital recoverable through a CTC, exclusive of related carrying costs, projected to be collected through the date of the final order in the true-up proceeding.

(B) Above-market purchased power costs arising from contracts in effect before January 1, 1999, including any amendments and revisions to such contracts resulting from litigation initiated before January 1, 1999.

(i) The purchased power market value of the demand and energy included in the purchased power contracts shall be determined by using the weighted average costs of the highest three offers from a bona fide third-party transaction or transactions on the open market.

(ii) The bona fide third-party transaction or transactions on the open market shall be structured so that the above-market purchased power costs are determined pursuant to subclause (I) or (II) of this clause.

(I) A transaction may be structured so the electric utility pays a third party to assume the utility's obligations under the purchased power contract. The weighted average of the three highest offers received in the transaction establishes the above-market purchased power costs.

(II) A transaction may be structured so a third party pays the utility to take power under the purchased power contract. The difference between the net present value of obligations under the existing contracts at the utility's cost of capital and the weighted average of the three highest offers received in the transaction establishes the above-market purchased power costs.

(C) Deferred debits, to the extent they have not been securitized, related to a utility's discontinuance of the application of SFAS No. 71 ("Accounting for the Effects of Certain Types of Regulation") for generation-related assets if required by PURA Chapter 39.

(D) Capital costs incurred before May 1, 2003 to improve air quality to the extent they have been approved by the commission pursuant to §25.261 of this title (relating to Stranded Cost Recovery of Environmental Cleanup Costs).

(E) Any adjustments resulting from the commission's review of the TDU's, APGC's, and AREP's efforts pursuant to subsection (e)(4) of this section.

(h) **True-up of final fuel balance.**

(1) An APGC shall reconcile the former electric utility's final fuel balance determined under PURA §39.202(c).

(2) The final fuel balance shall be reduced by any revenues collected by the AREP under any commission-approved fuel surcharge, from the date of introduction of competition to the utility's customers through the date of the true-up filing under this section, so long as the fuel surcharge is associated with fuel costs incurred during the time period covered by the final reconcilable fuel balance.

(3) If an electric utility or its TDU or APGC is assessed by another utility in Texas a fuel surcharge after 2001 for under-recoveries occurring through the end of 2001, the surcharged utility shall add the amount of surcharges and any associated carrying costs paid after 2001 to its final fuel balance.

(4) The final fuel balance, as adjusted by paragraphs (2) and (3) of this subsection, shall include carrying costs on the positive or negative fuel balance equal to:

(A) the weighted-average cost of capital approved in the company's unbundled cost of service (UCOS) proceeding, if the period until the date of the final true-up order is greater than one year; or

(B) the rate approved in §25.236 of this title (relating to Recovery of Fuel Costs) if the period until the date of the final true-up order is one year or less.

(i) **True-up of capacity auction proceeds.**

(1) For purposes of the true-up required by PURA §39.262(d)(2), and as provided for under §25.381(h)(1) of this title (relating to Capacity Auctions), the APGC shall compute the difference between the price of power obtained through the capacity auctions conducted for the years 2002 and 2003 and the power cost projections for the same time period as used in the determination of ECOM for that utility in the proceeding under PURA §39.201. The difference shall be calculated according to the following formula: (ECOM market revenues – ECOM fuel costs) – ((capacity auction price x total 2002 and 2003 busbar sales) – actual 2002 and 2003 fuel costs). For purposes of this paragraph:

(A) "ECOM market revenues" shall be the sum of rows 12 through 14 for the years 2002 and 2003 in the "Plant Economics" worksheet of the ECOM model underlying the commission-approved ECOM estimate in the company's UCOS proceeding;

(B) "ECOM fuel costs" shall be the sum of rows 33 through 35 for the years 2002 and 2003 in the "Cost Partition" worksheet of the ECOM model underlying the commission-approved ECOM estimate in the company's UCOS proceeding;

(C) The "capacity auction price" shall be the APGC's total capacity auction revenues derived from the capacity auctions conducted for the years 2002 and 2003 divided by that APGC's total MWh sales of capacity auction products for the years 2002 and 2003.

(2) If, as a result of not having participated in capacity auctions pursuant to §25.381(h)(1) of this title, an APGC is unable to determine a company-specific capacity auction price, the APGC may request in its true-up application a method using prevailing capacity auction prices from other APGCs for the calculation in paragraph (1) of this subsection.

(j) **True-up of PTB revenues.** This subsection specifies how the PTB will be compared to prevailing market prices pursuant to PURA §39.262(e). For purposes of this subsection, the term "small commercial customer" does not include unmetered lighting accounts unless such an account has historically been treated as a separate customer for billing purposes.

(1) An AREP is not required to perform the reconciliation described in PURA §39.262(e) for the residential or small commercial customer class if the commission has determined that the AREP has reached the applicable 40%

threshold requirements prior to January 1, 2004, pursuant to filing requirements listed in §25.41(l) of this title (relating to Price to Beat) applicable to that class.

(2) If an AREP has not reached the applicable 40% threshold requirements prior to January 1, 2004, for either the residential or the small commercial class, or both, the net PTB for each such class must be compared to the market price of electricity for that class in the TDU region for the period January 1, 2002 through January 1, 2004 as provided in paragraphs (3) and (4) of this subsection.

(3) The independent third party shall compute the difference between the residential net PTB and the residential market price of electricity on the last day of each calendar-year quarter for the years 2002 and 2003. The price differential for each quarter shall be multiplied by the total kWh consumed by residential PTB customers of the AREP for that quarter. The results shall be summed over the eight quarters within the period from January 1, 2002 through January 1, 2004.

(4) The independent third party shall compute the difference between the small commercial net PTB and the small commercial market price of electricity on the last day of each calendar-year quarter for the years 2002 and 2003. The price differential for each quarter shall be multiplied by the total kWh consumed by small commercial PTB customers of the AREP for that quarter. The results shall be summed over the eight quarters within the period from January 1, 2002 through January 1, 2004.

(5) For each of the residential and small commercial classes, the AREP shall credit the TDU the lesser of the amounts calculated in subparagraphs (A) and (B) of this paragraph:

(A) $150 multiplied by (the difference between the number of residential or small commercial customers, as applicable, in the TDU Region taking PTB service from the AREP on January 1, 2004 and the number of residential or small commercial customers, as applicable, outside the TDU region being served by the AREP on January 1, 2004, provided that such customers are not receiving POLR service from the AREP); or

(B) the total differential between the net PTB and the market price of electricity calculated for the applicable class under paragraph (3) or (4) of this subsection.

(6) All REPs shall provide information to the independent third party as needed for the performance of calculations set forth in paragraphs (3) and (4) of this subsection. All data used in the calculations performed by the independent third party will remain confidential but shall be subject to audit by the commission.

(7) The functions of the independent third party shall be funded by the AREPs through one or more assessments made by the commission.

(k) **Regulatory assets.** To the extent that any amount of regulatory assets included in a TC or CTC exceeds the amount of regulatory assets approved in a rate order which became effective on or before September 1, 1999, the commission shall conduct a review during the true-up proceeding to determine any such amounts that were not appropriately calculated or that did not constitute reasonable and necessary costs. In addition, to the extent that any amount of regulatory assets approved for securitization in a commission financing order was not subsequently included in an issuance of transition bonds, that amount of regulatory assets shall be included in the TDU/APGC true-up balance under subsection (l) of this section.

(l) **TDU/APGC True-up balance.**

(1) The formula to establish the true-up balance between the TDU and APGC is shown in the following table. TDUs described in subsection (d)(3) of this section and their APGCs shall insert zero for all inputs in this equation except the input entitled "Final fuel balance calculated pursuant to subsection (h)."

	Calculation of True-up Balance
	Net book value calculated pursuant to subsection (g)
-	Market value calculated pursuant to subsection (f)(1)
+/-	Value calculated by ECOM model pursuant to subsection (f)(2)
+/-	Final fuel balance calculated pursuant to subsection (h)
+/-	Capacity auction true-up calculated pursuant to subsection (i)

+/-	<u>Regulatory asset amount calculated pursuant to subsection (k)</u>
=	TDU/APGC True-up Balance

(2) For TDUs described in subsection (d)(2) of this section, the TDU/APGC true-up balance shall be compared to projected stranded costs as provided in subparagraphs (A) – (C) of this paragraph. For TDUs described in subsection (d)(3) of this section, the TDU/APGC true-up balance shall be treated as provided in subparagraph (D) of this paragraph.

(A) If the TDU/APGC true-up balance is positive, and greater than projected stranded costs, then the commission shall increase the CTC (or establish a CTC, if no CTC has previously been approved for the utility), extend the time for the collection of the CTC, or both, to enable the TDU to collect the TDU/APGC true-up balance. The utility may seek to securitize any or all of the amounts determined under this subparagraph under PURA Chapter 39, Subchapter G.

(B) If the TDU/APGC true-up balance is positive, but less than projected stranded costs, then the commission shall reduce nonbypassable delivery rates in the amount of the difference by:

(i) reducing any CTC established under PURA §39.201;

(ii) reversing, in whole or in part, the depreciation expense that has been redirected under PURA §39.256;

(iii) reducing the TDU's rates; or

(iv) any combination of clauses (i), (ii), and (iii) of this subparagraph.

(C) If the TDU/APGC true-up balance is negative, then

(i) any CTC established under PURA §39.201 shall be eliminated;

(ii) net mitigation shall be reversed until exhausted or until a zero true-up balance is achieved, and the amount of net mitigation reversed shall be returned to ratepayers by the APGC through an excess mitigation credit; and

(iii) if net mitigation is exhausted and some amount of the negative true-up balance remains, then for companies that have securitized regulatory assets, a negative CTC shall be established based upon the lesser of the absolute value of the remaining negative true-up balance or the securitization amount on which any TCs are based. If the company has been issued a financing order by the commission authorizing the securitization of regulatory assets but securitization has not yet occurred, then the negative CTC will be implemented at the time the securitization bonds are issued. If the company has not received a financing order from the commission authorizing securitization of regulatory assets, then no negative CTC shall be established for purposes of this subsection.

(D) If the TDU/APGC true-up balance is positive, then a CTC shall be imposed to enable the APGC to recover any positive fuel balance. If the TDU/APGC true-up balance is negative, then a fuel credit shall be implemented to return the over-recovered fuel balance to ratepayers.

(3) The TDU shall be allowed to recover, or shall be liable for, carrying costs on the true-up balance. Carrying costs shall be calculated using the utility's cost of capital established in the utility's UCOS proceeding, and shall be calculated for the period of time from the date of the true-up final order until fully recovered.

(m) **TDU/AREP true-up balance.** The TDU shall bill the AREP for, and the AREP shall remit to the TDU, the amount calculated pursuant to subsection (j) of this section, plus carrying costs. Carrying costs shall be calculated using the utility's cost of capital established in the utility's UCOS proceeding, and shall be calculated for the period of time from the date of the true-up final order until fully recovered. The commission may reduce the TDU's rates to reflect the amounts due from the AREP.

(n) **Proceeding subsequent to the true-up.**

(1) The TDU shall file an application to adjust its rates within 60 days following the issuance of a final, appealable order on its true-up proceeding. In the

proceeding, the commission may adjust the TDU's rates and any CTC, in accordance with PURA §39.262(g), and any excess mitigation credit. The commission may also allocate the recovery responsibility for such rates and any CTC to the TDU's customer classes.

(2) In the proceeding, the commission shall also consider adopting remittance standards, if necessary, with respect to the credits or bills as among the TDU, the APGC, and the AREP.

This agency hereby certifies that the rule, as adopted, has been reviewed by legal counsel and found to be within the agency's authority to adopt. It is therefore ordered by the Public Utility Commission of Texas that §25.263, relating to True-up Proceeding, is hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 3rd DAY OF DECEMBER 2001 .

PUBLIC UTILITY COMMISSION OF TEXAS

Chairman Max Yzaguirre

Commissioner Brett A. Perlman

Commissioner Rebecca Klein