PROJECT NO. 26556

RULEMAKING TO AMEND PUC SUBST. R. 25.41, RELATING TO PRICE TO BEAT	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING AMENDMENTS TO §25.41
AS APPROVED AT THE MARCH 5, 2003 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to §25.41 relating to Price to Beat with changes to the proposed text as published in the November 22, 2002 *Texas Register* (27 TexReg 10840). The amendments modify certain requirements related to adjustments to the price to beat, including: the number of trading days used to calculate the natural gas price average for fuel factor adjustments; the threshold of price changes needed to justify an adjustment to the fuel factors; the criteria that apply in order to substitute an electricity price index for the natural gas price index; the specific adjustments to the price to beat that will be considered following the true-up proceedings conducted under Public Utility Regulatory Act (PURA) §39.262; and the processing guidelines for price to beat adjustments. The amendments also make other minor changes that are intended to clarify other aspects of the rule. Project Number 26556 is assigned to this proceeding.

The amended §25.41 clarifies that the affiliated retail electric provider (REP) can request up to two adjustments each year to their price to beat fuel factor, upward or downward, upon a showing that the existing fuel factor does not adequately reflect significant changes in the market price of natural gas and purchased energy as measured by changes in natural gas futures prices. As adopted, the revised section requires the use of a 20-day average of the forward 12 month average market clearing price of natural gas traded on the New York Mercantile Exchange

(NYMEX) at the Henry Hub delivery point with a 5.0% materiality (or significance) threshold instead of the ten-day average and 4.0% threshold contained in the original rule. Because natural gas prices and electricity prices are very highly correlated in Texas, this adjustment will aid in the development of a robust competitive retail electricity market by continuing to permit the price to beat fuel factor to change in accordance with the market price of electricity, while reducing the potential that transitory changes in prices will be captured.

Amended §25.41 also provides for specific adjustments to the price to beat following the true-up proceedings as permitted by PURA §39.202(k). Specifically, the amended rule specifies that the commission will adjust the fuel factor portion of the price to beat rate downward following the true-up if natural gas prices are below the prices embedded in the then-current factors. Additionally, the base rate portion of the price to beat will be adjusted, upward or downward, in order to account for changes in the non-bypassable delivery charges billed to REPs by transmission and distribution utilities (TDUs). The combination of these two adjustments will provide needed certainty to both retail customers and market participants as to the changes that will occur following the true-up. These adjustments will also provide a benefit to retail customers on price to beat service of lower natural gas and purchased energy prices and non-bypassable charges, if prices fall, while also ensuring that increases in non-bypassable charges do not eliminate the ability of new entrants to effectively compete for retail customers.

Comments were received on December 13, 2002 and reply comments were received on December 20, 2002. Representatives from Consumers Union Southwest Regional Office, Texas

Ratepayers' Organization to Save Energy, and Texas Legal Services Center (Consumer Groups); TXU Energy Retail (TXU); the American Electric Power Retail Electric Providers (AEP REPs); Reliant Resources, Inc. (Reliant); City of Houston (Houston); Entergy Gulf State, Inc. (Entergy); the Office of Public Utility Counsel and the Steering Committee of Cities Served by TXU (OPC and Cities); Alliance for Retail Markets (ARM); the State of Texas (the State); and First Choice Power, Inc. (FCP) provided comments and responses to other parties' comments.

A public hearing on the proposed rule and registration form was held January 7, 2003 at 10:00 a.m. in the Commissioners' Hearing Room. No party made additional comments at the hearing.

The commission requested specific comments on the following questions:

1. The current rule provides for the use of a ten-day rolling average of NYMEX natural gas futures prices in order to determine whether or not a significant change in the market price of natural gas and purchased energy has occurred. While it does not appear that the recent adjustments to the price to beat fuel factors have captured a temporary change in natural gas price, but instead appear to have reflected significant and long-term price change, a review of natural gas prices over the course of 2002 suggests that there is a potential for capturing temporary changes in gas price due to the use of a ten-day average. Does the proposed change to a 20-day average, combined with the changes in the significance threshold reduce or minimize the potential for such an occurrence?

TXU, ARM, AEP REPs, Entergy, FCP, Reliant, OPC and Cities, and Houston agreed that adopting a 20 trading-day period does not reduce potential for capturing temporary changes in gas price.

TXU, ARM, AEP REPs, Entergy and FCP commented that it is highly unlikely that an affiliated REP can game fuel factor adjustments using the ten-day rolling average of natural gas prices and the current rule has consistently captured significant changes in the market price of natural gas and purchased power during the 13-month period analyzed (September 4, 2001 through October 10, 2002) by the commission. Reliant argued that there is no systematic ability of an affiliated REP to capture temporary changes in gas prices using either a ten-day average or a 20-day average because the path of future gas prices is unknown. FCP, ARM, and AEP REPs stated that the June 2002 decline in gas prices referenced in the Proposal for Publication as the basis for implementing a 20-day rolling average was transitory in nature, but the overall trend in gas price increases was not. FCP and ARM argued that the possibility of an affiliated REP capturing an inadvertent spike in gas prices should not be the basis for making the proposed change in trading days.

TXU, ARM, and Reliant commented that lengthening the amount of time it takes to implement revisions to the fuel factor component of the price to beat rates increases the risk that will be borne by both affiliated REPs and competitive REPs because the existing retail prices fail to reflect wholesale purchased energy prices. ARM and Reliant argued that using a longer time period, along with the regulatory schedule, creates significant lag between the wholesale market price changes and retail market price changes. ARM noted that the greater the number of trading days used to calculate average prices increases, the greater the lag from actual market prices. Reliant stated that this was not an issue under the former regulatory regime because utilities were allowed to recover purchased energy costs through a fuel surcharge. No such mechanism exists for affiliated REPs. In turn, ARM and Reliant argued, the greater the lag from actual market prices, the more difficult it is for all REPs to effectively manage their risk in the market. FCP added that affiliated REPs specifically would lose revenues due to this proposed change, hampering the company's ability to compete outside of their service area, therefore harming competition.

TXU, FCP, and Entergy argued that there is not a substantial difference between using a ten-day period, a 15-day period, or a 20-day period; therefore, they argued that the ten-day period should be retained in the rule. FCP agreed, stating that there is only a 2.0% variance between the ten- and 20-day rolling averages.

OPC and Cities agreed that there is virtually no difference between the ten-day and 20-day averages with respect to problems of transitory price changes discussed by the commission. But Houston and OPC and Cities argued that adoption of the 20-day average would not really further the commission's goal of reducing "gaming" opportunities by eliminating transitory price spikes and that the commission should require an even longer trading-day period to evaluate true trends in natural gas prices. OPC and Cities point out that TXU and FCP agree with them that there is little difference between ten and 20 days, citing this as evidence that a longer time frame is needed to prevent gaming.

TXU and Entergy commented that a 20 trading-day period would add at least 14 more calendar days to the length of time it takes to change the fuel factor to reflect wholesale prices. TXU stated that using a 20 trading-day period would require at least 28 calendar days, followed by several days to make the filing, followed by 45 days (or more, under the proposed revisions) until a final order is entered by the commission. Thus, TXU stated, there would be approximately 75 days between the time wholesale prices begin to change and the time that such change can be reflected in the price to beat fuel factor. Entergy stated that if the 20 trading-day period is adopted, then they proposed that the discretionary procedural deadlines be made mandatory and changed as follows: the deadline for requesting a hearing (if any) be reduced from 15 days to seven days after the petition is filed; and if a hearing is requested, the final order issuance date be reduced from 45 days to no later than 30 days. These changes, Entergy argued, would make up for the filing time lost by extending the trading day period from ten to 20 days. Cities and OPC believe these proposals would severely disadvantage interveners by limiting the time for analysis and preparation of testimony, as well as seriously limiting the time available for the ALJ and commission to analyze cases. Cities and OPC further argued that the shortened time frame, from 15 to seven days, would also make it more, rather than less, likely that parties would request hearings to preserve their rights, and would make reaching a settlement in advance more difficult. OPC and Cities reiterate that Entergy has not provided any proof that these additional ten days would have any actual financial impact. OPC and Cities point out that the reduction of the filing window from ten days to one fulfills the same function of offsetting the increase from a ten to a 20 day rolling average. The State suggested that affiliated REPs' statements that costs and revenues are irrelevant to the statutory requirement to demonstrate losses, and their claim of the possibility of losses due to a delay, are inconsistent.

While the commission agrees with virtually all of the parties that suggest that the move to a 20-day period does not result in a substantial change in the average used to calculate gas price adjustments, no party refuted the potential that, based on actual gas prices that occurred in 2002, there was in fact a period of time that the use of a ten-day average captured a transitory period of natural gas price increases that a 20-day average would not have.

The commission agrees with Reliant and others that there is no systematic way for an affiliated REP to "time" the natural gas market in order to capture temporary spikes in natural gas prices; however, the commission remains concerned that prices for a ten-day average have demonstrated the potential for an affiliated REP to capture a transitory change in natural gas prices, intentionally or not.

The commission also agrees with TXU, FCP, and others who argue that the increase in the number of days used to average gas prices may result in the gas price average becoming further divorced from how prices are actually changing in the marketplace, especially given the time needed to process requests for adjustments. However, the commission believes that a move to a 20 trading-day period would provide a slight benefit over a 10-day or 15-day trading period to smooth price spikes in the gas market, but still retain the timeliness to adequately reflect market prices. The commission also believes that a 20 trading-day average, combined with the increase to a 5.0% materiality (or significance) threshold, and the change in the filing window would adequately address the concern discussed by the commission in the preamble to the published rule. The commission makes corresponding changes in the rule.

For the reasons discussed above, the commission disagrees with OPC and Cities and others who argued that the similarity between the ten-day and 20-day average supported the use of an even longer period of time to average natural gas prices. As stated in the original Order Adopting §25.41, Relating to Price to Beat, if the price to beat does not remain an above-market rate with adequate headroom for new providers to enter the market and be able to profitably compete for retail customers, then retail competition in Texas will not succeed. (*Price to Beat*, Project Number 21409 (Mar. 21, 2001)) The transcript of the floor debate in the Texas House of Representatives provided by OPC illustrates that this was of paramount concern to the Legislature. Representative Steve Wolens, the sponsor of Senate Bill 7 (Act of May 27, 1999, 76th Legislature, R.S., Ch 405, 1999 Texas General Laws 2543) in the House stated: "And that is the genius of this bill. If you want competition, they (competitors) have got to come in, and they got to have headroom to be able to come in and price." (See OPC Comments at 38.)

Additionally, the requirement that the affiliated REP lose 40% of the load in their residential and small commercial customer classes before each is permitted to offer other products than price to beat service in their own area also illustrates the intent of the Legislature that the price to beat contain sufficient headroom such that new entrants could entice customers to switch to a new provider.

Also, PURA §39.262 provides that the affiliated REP is required to refund the difference between the price to beat and the prevailing market price of electricity (subject to certain limitations) at the time of the true-up. This further illustrates that the Legislature intended and expected the price to beat to be an above market rate.

It is therefore inconsistent with this intent for the price to beat to become significantly divorced from the market price of electricity. The greater the number of days that are averaged to compute the natural gas price average, the greater the potential that that average will significantly lag behind changes in market prices. The commission agrees with the comments of Reliant and others that argue that natural gas and electricity prices are very highly correlated in Texas, a significant lag in natural gas prices correlates very strongly to a significant lag in the market price of electricity. As such, the commission declines to make the changes suggested by OPC and Cities and finds that the use a 20-day average, combined with the other changes to the rule discussed herein, mitigates the potential that temporary spikes in prices would be captured by an affiliated REP's request, while still retaining a sufficiently close reflection of actual conditions in natural gas and purchased energy markets.

2. In order to provide more certainty to both retail customers and the marketplace, the commission has proposed additional detail as to what factors will be considered with

respect to adjustments to the price to beat following the stranded cost true-up proceedings pursuant to the commission's authority under PURA §39.202. Is the proposed methodology appropriate, or should a different adjustment mechanism be used? If the commission instead ordered that the price to beat be adjusted (either up or down) such that initial headroom that existed on January 1, 2002 was achieved, what would be the proper method of distributing adjustments to the price to beat, between the base rate components and the fuel factor component of the price to beat?

Reliant, ARM, TXU, and FCP commented that the proposed methodology is appropriate. In addition, they supported the idea that any price changes pursuant to PURA §39.202(k) should be symmetric, reflecting increases or decreases in natural gas prices or non-bypassable charges. Reliant and TXU recommended that, should market prices indicate an increase in the price to beat fuel factor is warranted, the price to beat fuel factor be increased following the true-up. Likewise, Reliant and ARM suggested that the rule should clarify that the base rate adjustment should include any "known and measurable changes" to the TDU's non-bypassable charges. FCP agreed and specifically argued that any increase in the non-bypassable charges resulting from a competitive transition charge (CTC) should result in an increase in the base rate component of the price to beat rate, after updating for gas prices. FCP argued that the base component of the price to beat rate applicable to the non-bypassable charges should not be adjusted outside the normal regulatory proceeding for the TDU. FCP also stated that if the intent of the rule is to have a different TDU rate for price to beat customers and for competitive customers, then FCP opposed this portion of the rule because it would result in billing of two sets of TDU rates.

In reply comments, OPC and Cities stated that, while they do not object to the fuel factor adjustments being symmetric, the current rule and proposed amendments allow no opportunity for the fuel factor to be reduced under PURA §39.202(l) filings and that only a potential downward adjustment should be allowed under the PURA §39.202(k) true-up adjustment, because affiliated REPs would still have the opportunity to make a filing under PURA §39.202(l) if an increase is needed. In reply comments, AEP REPs disagreed with OPC and Cities and Houston's objection to changing fuel factor rates during the true-up proceeding and stated that because price to beat fuel factor changes are not cost-based changes, the commission should reject their argument.

The commission notes that all customers, irrespective of whether customers are receiving price to beat service or not, are assessed the same non-bypassable charges. Also, the commission notes that the base rates of the price to beat are set by law as a 6.0% reduction of the rates in effect on January 1, 1999, and are not directly related to the non-bypassable charges set by the commission in the relevant unbundled cost of service proceeding. Therefore, it appears that FCP's concerns do not require revisions to the rule.

The commission agrees that all changes in non-bypassable charges should be reflected in the adjustment to be made following the true-up, including changes in stranded cost charges and transmission and distribution rates, and that this should be symmetrical with respect to these charges. Clarifying language has been added to subsection (g)(3)(B).

The commission disagrees that the fuel factor adjustment contemplated by (g)(3)(A) should be symmetric. The commission finds that it is appropriate to provide certainty to retail customers that a downward adjustment to the fuel factor will be made if natural gas and electricity prices warrant such an adjustment. The commission notes that affiliated REPs would still retain their ability to request an adjustment to the fuel factor if natural gas prices increase up to twice per year. No revision to the proposed rule has been made.

Entergy commented that the proposed amendments to the price to beat rule could result in a decrease in the shopping credit because there is not a provision that allows the commission to account for the shopping credit margin. Instead, Entergy argued, the proposed fuel factor revisions appear to require either the status quo or a downward adjustment based solely on NYMEX gas prices but does not attempt to measure the "before" and "after" shopping credit. Entergy argued that if the shopping credit is reduced to a level below its pre-true-up level, then competition in the retail market will be irrevocably harmed. Entergy stated that whatever the commission decides with regard to the price to beat rule, it should ensure that the resulting shopping credit is at least the same as the pre-true-up shopping credit, if not increased, as necessary to protect and enhance the competitive retail market. Entergy argued that the proposed amendments to the rule limit the commission's ability to ensure a healthy competitive retail market by presuming that PURA §39.202(k) is intended to result in a post-true-up affiliated REP headroom level that is no more than headroom that existed initially in the market and that PURA does not require this limited result. Entergy stated that PURA §39.202(k) authorizes a discretionary action, but does not require that the commission adjust the price to beat and does not require that the post-true-up adjustment to the price to beat simply maintain the then-existing price to beat headroom level to the initial price to beat headroom level. Entergy argued that the commission should retain flexibility to ensure that competitive REPs are not forced out or otherwise adversely affected by changes to the affiliated REPs' price to beat rates. Entergy suggested that this could be achieved by ensuring that the post-adjustment shopping credit is at least no less than the pre-adjustment shopping credit. In reply comments, ARM agreed with Entergy's observation that the language in PURA §39.202(k) gives the commission full discretion as to the scope and degree of any adjustment to the price to beat following the true-up but argued that it does not preclude the commission from establishing the restoration of eroded headroom in the future proceeding envisioned by this provision. ARM also stated that they agree with Entergy's position that the statutory provision permits the commission to adjust the price to beat in a manner that affords greater headroom than that which existed on January 1, 2002, if it concludes that additional headroom is necessary.

The commission declines to make the change suggested by Entergy. The commission believes that the adjustments proposed in the rule combined with the ability of the affiliated REP to request up to two adjustments per year should be adequate to maintain a sufficient amount of headroom in the price to beat. The commission disagrees with Entergy that the rule contemplates either a status quo or downward adjustment to the fuel factor and notes that affiliated REPs are permitted to request two adjustments to the fuel factor per year if changes in the market price of natural gas and purchased energy warrant. Therefore, to the extent the market price of natural gas and purchased energy increases, thereby reducing headroom, a mechanism already exists for the affiliated REP to remedy that headroom decrease by requesting an upward adjustment to its fuel factor. The commission also finds that, if the "shopping credit" or headroom is reduced due to increases in non-bypassable charges, the rule as proposed addresses that concern through providing for an adjustment to the base rates to account for that. Therefore, no change to the proposed rule has been made.

The commission agrees that the statute does provide the commission with great flexibility as to how the price to beat should be adjusted following the true-up, and the commission agrees that it is not precluded from considering adjustments to the price to beat to create additional headroom. However, the commission believes it appropriate, as stated in the preamble to the proposed rule, to provide additional certainty and guidance as to what adjustments will be made at that time, in order to better assist both REPs and customers in making arrangements for electric service. No change has been made to the proposed rule.

In reply comments, Houston, OPC and Cities opposed Entergy's proposal to arbitrarily adjust the price to beat to "ensure a healthy retail open access market" because they argued this language much too broad and subjective. However, OPC and Cities did support Entergy's argument that PURA §39.202(k) places no limit on the commission's ability to adjust the base rate component of the price to beat. OPC and Cities argued that the level of price increases needed to achieve healthy retail open market access are unknown and there is no way to determine what the outcome of such a proposal might lead to in terms of regulatory proceedings. OPC and Cities also stated that the whole concept of "price supports" from ratepayers to subsidize the competitive market is antithetical to the entire concept of free market, the price to beat, and economic theory.

The commission agrees with Houston and OPC and Cities that Entergy's proposed language is extremely broad and does not add much in the way of certainty to the marketplace and customers. The commission therefore declines to make the changes suggested by Entergy. However, to the extent that OPC and Cities' concept of "price supports" is meant to indicate that the price to beat was not intended to be an above market rate, the commission disagrees for the reasons previously stated.

Houston did not support the proposed addition of subsection (g)(3)(B) to adjust the base rate portion of the price to beat to account for adjustments in non-bypassable fees. Houston argued the proposal of subsection (g)(3)(B) is inappropriate and contrary to PURA because they believe that it will likely result in an increase in the price to beat for the sake of certainty. Houston stated that the proposed mechanism would provide for an automatic adjustment to rates without any cost support and that PURA has a prohibition on automatic adjustments to rates. Houston argued that the mechanism could increase the price to beat base rates even if the utility's costs have not changed, or may have even decreased creating a windfall that would flow to the utility's bottom line. Houston stated that this windfall should instead flow back to the customer rather than the utility and that if the windfall is used to reduce stranded costs the mechanism has succeeded in a more rapid recovery of stranded costs.

PURA's prohibition on automatic adjustments to rates is included in PURA §36.201, which states that "the commission may not establish a rate or tariff that authorizes an *electric utility* to automatically adjust and pass through to the utility's customers a change in the *utility's* fuel or other costs (emphasis added)." PURA §31.002(6)(H) explicitly excludes retail electric providers from the definition of "electric utility." Therefore, the commission finds there is no explicit prohibition on automatic rate adjustments for retail electric providers.

Moreover, the commission disagrees that the adjustment contemplated in the proposed rule is an "automatic adjustment." PURA §39.107(d) provides that a transmission and distribution utility "shall bill a customer's retail electric provider for non-bypassable delivery charges" and that the REP "must pay these charges." As such, it is unquestioned that changes in non-bypassable delivery charges are a cost to REPs and may change as a result of the true-up proceeding. PURA §39.202(k) permits the commission to adjust the price to beat following the true-up proceedings. Subsection (g)(3) merely prescribes the type of adjustment that will be considered by the commission following the true-up and specifies a methodology to effectuate that adjustment. Subsection (g)(3) also contemplates filings to be made by the affiliated REPs for the commission to review and approve the adjustments and ensure that they are performed in accordance with the rule methodology. Adjustments to the rates will not occur without commission review and approval, and therefore, the commission does not agree that the adjustments are automatic.

ARM suggested that the commission revise subsection (g)(3) to state that: (1) the price to beat shall be adjusted to a level, that at a minimum, achieves the same amount of headroom which existed on January 1, 2002; and (2) after re-achieving the original amount of headroom in existence on January 1, 2002, the commission may further increase the adjusted price to beat in order to "encourage full and fair competition among all providers of electricity," consistent with the legislative objective in PURA §39.101(b)(1).

TXU disagreed with ARM and opposed the possibility of using an adjustment based on the amount of headroom that existed on January 1, 2002. TXU commented that such an approach would be more difficult to implement than the approach contained in the proposed rule, as the commission explicitly declined to calculate the amount of headroom when it decided the initial price to beat cases for the affiliated REPs.

AEP REPs proposed that the commission retain an option to adjust price to beat rates to preserve headroom and that if additional adjustment is made to price to beat rates solely to preserve pre-existing headroom, the change should be applied to the price to beat fuel factor, consistent with the way such changes are to be handled in price to beat fuel factor filings at the request of the affiliated REP.

The commission agrees with TXU and declines to make the changes proposed by ARM and AEP REPs for the same reasons as discussed above with respect to the similar proposal by Entergy.

The commission believes that the combination of an adjustment to the base rates to account for changes in the non-bypassable charges assessed to REPs, and the adjustments to the fuel factors that can be requested by the affiliated REPs to reflect significant change in the market price of natural gas and purchased energy, are sufficient to retain headroom under the price to beat for new competitors.

AEP REPs, Entergy, TXU, and Reliant suggested that the commission clarify that if a fuel factor adjustment is made pursuant to subsection (g)(3)(A), that adjustment will not reduce the number of adjustments the affiliated REP may request pursuant to §25.41(g)(1). AEP REPs stated that PURA §39.202(l) permits affiliated REPs to request two changes per year. AEP REPs argued that if the commission, under separate rule authority, allows adjustments during the true-up, that adjustment cannot be considered a request by the REP pursuant to PURA §39.202(l). TXU and AEP REPs agreed that an adjustment to the price to beat following the true-up would be undertaken pursuant to PURA §39.202(k), not requests to adjust the fuel factor under PURA §39.202(l). In reply comments, Reliant suggested that if the commission decides that a fuel factor adjustment pursuant to subsection (g)(3)(A) is considered one of the affiliated REPs two allowed fuel factor adjustments per year, then such a fuel factor adjustment should be made at the affiliated REP's option.

The commission agrees with AEP REPs, Entergy, TXU, and Reliant that it is appropriate to clarify that the adjustment contemplated in (g)(3)(A) is not intended to reduce the number of adjustments that the affiliated REP may request. Adjustments to the price to beat made by the commission following the true-up are pursuant to PURA §39.202(k), whereas PURA §39.202(l) provides separately for adjustments to the fuel factor requested by the affiliated REP. A clarifying addition to this subsection has been made.

Entergy opposed proposed subsection (g)(3)(A) to allow for a fuel factor adjustment following the true-up. Entergy stated that PURA does not give the commission unfettered discretion to adjust any component of the price to beat. Entergy argued that, while the commission has the discretion to adjust the base rate components of the price to beat, it does not have the discretion to adjust the fuel factor components. Entergy commented that fuel factor adjustments are filed at the sole discretion of the affiliated REP in accordance with PURA §39.202(l) and that the proposed addition of subsection (g)(3)(A) inappropriately would allow the commission to adjust both the base rate components and the fuel factor components of an affiliated REP's price to beat by requiring an affiliated REP to do something that the commission does not have the authority to do under PURA §39.202(l).

The commission agrees with Entergy that only the affiliated REP has the right to request adjustments to the price to beat fuel factor under PURA §39.202(l). Specifically, in the Order Adopting §25.41, the commission found that, "under the plain language of PURA §39.202(l), only the affiliated REP can request a change in the fuel factor portion of the price to beat."

However, the commission does not agree that it lacks authority to require an adjustment to the fuel factor following the true-up. PURA §39.202(k) contains no limitation on the commission's authority to adjust the price to beat following the true-up. The commission believes it appropriate to provide for two separate adjustments at that time — one to reflect lower natural gas and power prices, if appropriate, and one to reflect changes in non-bypassable charges, also if appropriate. The commission finds that these two adjustments, together with the continued ability of affiliated REPs to request adjustments to the price to beat fuel factor, provide a reasonable method to ensure that all retail customers, including those that remain on price to beat service, will receive the benefits of lower natural gas and power prices, while at the same time continuing to ensure that there is adequate headroom under the price to beat for new competitors to enter the market.

TXU and ARM agreed that only the base rate components of the price to beat should be adjusted in the proceeding conducted pursuant to subsection (g)(3). TXU commented that the fuel factor portion of the price to beat rate can vary over time so that it will, in general, reflect the wholesale energy prices available to the REPs and that the price to beat rates will reflect the energy prices that competitive REPs pay and upon which those competitive REPs base their retail prices. Therefore, the only portion of the price to beat rate where "headroom" can exist is the base rate portion. TXU argued that any attempt to achieve a certain amount of "headroom" in the fuel factor portion is subject to being lost whenever the affiliated REP requests a change to the price to beat fuel factor. Thus, TXU argued, to ensure that the headroom differential remains intact, it must be fully reflected in the base rate portion of the price to beat, while the fuel factor portion of the price to beat rate should continue to be set as otherwise provided in the price to beat rule.

The commission agrees with TXU's comments, and believes that retaining the proposed adjustment mechanism in the rule is consistent with those comments because changes in non-bypassable charges (which have the effect of changing headroom) are applied to the base rate portion of the price to beat.

ARM stated that, while they appreciate the commission's objective to recapture lost headroom attributable to a net increase in non-bypassable charges in the proposed revision to subsection (g)(3), such a discrete adjustment to the price to beat will not capture the numerous other factors that will increase the market price of power and erode headroom during the period in which the price to beat is in effect. These factors include, but are not limited to, the following: increases in the Electric Reliability Council of Texas (ERCOT) administrative fee; reliability must run (RMR) contracts approved by ERCOT; the potential for future plant mothballing and future RMR contracts; the possibility that plant mothballing and retirement will result in a decrease in the level of competition in the wholesale market; potential increases in fuel prices; the approval and implementation of non-bypassable charges; and the possibility that the commission may order the institution of a generation adequacy mechanism in Project Number 24255, *Rulemaking Concerning Planning Reserve Margin Requirements*. Entergy agreed and argued that the impact of these factors could seriously impair, and possibly eliminate, retail competition if they are not all taken into account in adjusting the price to beat pursuant to subsection (g)(3).

In reply comments, OPC and Cities opposed ARM's suggestion that the commission consider such items as ERCOT fees, RMR costs, and potential costs such as generation surcharge because, they argued, allowing such costs would greatly complicate the true-up proceeding. OPC and Cities argued that the commission should reject ARM's proposed language to allow the commission to increase the price to beat during the true-up proceeding due to such costs and argued that there would be nothing transparent or predictable about a rule that says the commission could arbitrarily increase the price to beat to encourage competition.

The commission agrees with OPC and Cities that items such as RMR costs and costs related to generation adequacy proposals should not, at this time, be included in the adjustment mechanism to follow the true-up proceeding. The commission notes that it is still evaluating the appropriate mechanisms for generation adequacy and it is therefore premature at this time to consider whether the costs that are required to be borne by REPs under such proposals be reflected explicitly in the price to beat. The commission finds that ARM's concerns regarding changes in fuel costs have been addressed through PURA §39.202(l), which permits the affiliated REP to request adjustments to their fuel factors to reflect changes in the market price of natural gas. The commission also notes that, the retirement of older generation plants typically occurs because these plants are less efficient and therefore no longer economic to run. While it is possible that decreased reserve margins may lead to higher wholesale market prices in the future (setting aside the effect of natural gas price changes), the commission believes that such changes will be captured either by the current mechanism contained in subsection (g)(2), or through the transition from a natural gas price index to an electricity commodity price index contemplated in subsection (g)(1).

The commission also recognizes that costs related to RMR contracts, and a variety of other costs, do represent real costs to REPs operating in the marketplace. However, the commission declines at this time to provide for an adjustment to the price to beat for these costs. The commission notes that ERCOT currently has a working group addressing RMR issues, and the commission is currently investigating whether more extensive changes to the wholesale market design in ERCOT is needed to remedy such costs. Therefore, the commission believes that it is inappropriate at this time to provide for an adjustment to the price to beat for these costs.

The commission also notes that the initial price to beat fuel factors included costs (22 cents per MWh) related to the ERCOT administrative fee. Because the initial level of the fee was included in the fuel factor portion of the rate, it has effectively been increased due to the subsequent adjustments to the fuel factors. The commission therefore finds that, although it is not a perfect match with the actual changes in the ERCOT administrative fee and that changes in the ERCOT administrative fee and changes in natural gas prices are unrelated, that there has effectively been an adjustment for the increased fee through the fuel factor adjustment mechanism.

Houston opposed the proposed method of calculating the price to beat base rate adjustment in subsection (g)(3)(B). Houston commented that as proposed, the rate adjustment is based on rate calculations for a typical commercial customer based on the assumption of "35 kilowatts (kW) of demand and 15,000 kWh per month in usage" and that, as defined, the typical customer has a load factor of approximately 59%. Houston stated that the price to beat rate adjustment necessary to maintain the prior level of headroom for this load factor will not be appropriate for commercial customers with different load factors and that the result would be to have lower and higher headroom levels (as compared to their initial headroom levels) for most commercial customers, contrary to the intent of the proposed mechanism. Houston stated that although they do not believe the proposed price to beat base rate adjustment mechanism is appropriate, they are not recommending an alternate method.

The commission disagrees with Houston and retains the proposed adjustment mechanism. The commission notes that changes to the base rates required under this subsection will be applied equally to each rate component, and therefore, should generally have the same level of impact on all customers, irrespective of load factor. While it may be the case that some customers will have greater amounts of headroom than others, the commission believes that this will predominantly be due to the particulars of the existing rate design of price to beat rates and non-bypassable charges, and that any incremental change in those rates will have relatively minor impacts.

In reply comments, ARM disagreed with Houston, arguing that an adjustment pursuant to subsection (g)(3)(B) does not result in an automatic adjustment as Houston claims. The proposed adjustment would only occur after a proceeding before the commission to determine whether the adjustment was appropriate. Therefore a one-time adjustment following the true-up is not contrary to any statutory provision prohibiting automatic adjustment mechanisms.

The commission disagrees that the adjustment mechanisms provided for by the rule are automatic adjustments for the reasons previously stated.

TXU stated that it is their understanding that the difference between the average price to beat rate and the non-bypassable charges effective as of January 1, 2002 would be determined, and that differential would then be added to the level of non-bypassable charges in effect after the 2004 true-up proceedings to determine the base rate portion of the price to beat rate. TXU suggested that this differential be calculated for each affiliated REP and specifically included in the proposed rule so that all parties will know in advance the amount that will be added to an affiliate REP's non-bypassable charges to determine the base rate portion of the price to beat rate.

ARM opposed TXU's suggestion to include a calculated differential in the rule. ARM stated that while they agree that the differential between the average price to beat and the non-bypassable charges in effect as of January 1, 2002 can be calculated now, ARM did not agree that the inclusion of those differentials in the rule is necessary. Instead, ARM argued, those differentials should be established as part of the proceedings established in subsection (g)(3) of this rule, in the event there is any disagreement about what they should be.

The commission agrees with TXU that the rule provides that the January 1, 2002 average price to beat rate and the non-bypassable charges differential would be added to the level of non-bypassable charges in effect after the 2004 true-up proceedings to determine the base rate portion of the price to beat rate. However, the commission agrees with ARM that it is unnecessary to include those mathematical calculations in the rule and that it is more appropriate that those differentials are filed in the true-up cases.

OPC and Cities supported the proposed amendments to allow adjustments for changes in the market price of energy used to serve retail customers and the retail clawback, but disagree with the other aspects of this proposal. OPC and Cities stated that the retail clawback is the only true-up provision which is specific to the price to beat. They argued that unless the retail clawback credits are flowed through to the price to beat customers, the largest part of the affiliated REP "excess earnings" would only be returned to the affiliated REP resulting in little or no cost to the affiliated REP for charging above-market prices to 60% or more of the retail market. OPC and Cities stated that if the retail clawback is to perform a function analogous to a fuel reconciliation, as some market participants have argued, then the credit must be reflected on end-users' bills.

The commission agrees with OPC and Cities that it is appropriate to include the retail clawback in the proposed adjustment to the base rates and finds that the proposed amendment would effectively pass through the retail clawback credit to ratepayers. Specifically, §25.263(m) of this title (relating to True-up Proceedings), provides for a reduction to the rates of a TDU to reflect the retail clawback. The commission disagrees that this is the only change in non-bypassable charges that should be included. The commission finds that it is appropriate and reasonable to reflect all changes in non-bypassable charges, positive or negative, in the adjustment provision.

3. What objective criteria should the commission consider adopting with respect to what constitutes a "sufficiently liquid" electricity commodity index or trading hub? The commission desires comments on specific criteria, such as volume of trades, number of participants, spread between bid and ask prices, etc.

Houston, OPC and Cities, TXU, and Entergy generally agreed that the commission should wait to define objective standards that could be used to define a sufficiently liquid electricity commodity index or trading hub. They also agreed that a trading hub either does not currently exist or should not be defined at this time.

Reliant, AEP REPs, and ARM provided varying amounts of detail as to what would constitute a "sufficiently liquid" electricity commodity index or trading hub. Reliant stated that in order for an electric commodity index to be considered sufficiently liquid for purposes of the price to beat adjustment, the following characteristics would need to be met: it is published; it is consistently reported on a regular schedule and is widely available; it represents standardized forward products; buying or selling electricity in the market will not materially change the index price; it is mature (has been in existence at least one year with all of the characteristics here present for that time); and, it contains zonal price differences to reflect ERCOT's unique structure. Reliant added that spreads between bid and ask prices are not necessarily meaningful measures of an index because spreads are functions of, among other things, the underlying volatility of the commodity, the anticipated holding period, and interest rates, and therefore, not necessarily a good indicator of liquidity.

AEP REPs stated that the schedule for amendments to the price to beat rule does not provide ample time to develop the comprehensive language needed to determine when an electricity-trading index or trading hub exists. AEP REPs argued that the commission first should determine what products are being traded in ERCOT. For example, currently Seller's Choice and Zones(s) are traded in the hourly, day ahead, and term markets with zone differentials. In addition, the ERCOT wholesale markets trade a "heat rate" product that is dependent upon the natural gas settlement price. AEP REPs contended that trading a heat rate product is clear evidence that there is a high level of correlation between forward gas prices and power prices in ERCOT. AEP REPs stated that several parameters need to be considered when relying upon an index for commercial transactions such as: accounting; risk management; multi-months of trade volume; and, bid/ask spreads extending across the spring/fall shoulder periods as well as summer. AEP REPs recommended that, at a minimum, the criteria described below should be considered in establishing an electric index in ERCOT:

	Seller's Choice Long Term	Seller's Choice Short Term	Zone Long Term Spread	Zone Short Term Spread
Trading Vol. MW per day (1)	500	3,000	500	1,500
# Active Participants (2)	10	20	5	10
# Active Brokers (3)	2	2	2	2
Bid/Ask Spread ($/MWh)	$1.00	$0.50	$0.50	$0.25
% Reported from Electronic Trading Platform Transactions	50%	50%	50%	50%

(1) Average volume should exceed this minimum by 20-50%;

(2) An active participant should at a minimum engage in one transaction per day every day; and

(3) An active broker should be a specialist whose primary focus is on the ERCOT market, who is responsible for creating liquidity in the market, and who engages in at least two transactions per day.

ARM commented that a "sufficiently liquid" electricity commodity index or trading hub used in lieu of the NYMEX natural gas price index should: be published, verifiable, and independent (e.g., an exchange); exhibit significant trading volume; demonstrate small bid/ask spreads; and, have at least two years of published price history. ARM added that these criteria could be expressly incorporated into subsection (g)(1)(F) and that if any of these criteria require subjective judgment, such further definition would need to be developed on a case-by-case basis in proceedings initiated pursuant to that subsection.

Responding to AEP REPs' and ARM's suggestion that the size of the bid/ask spread be used as one of the criteria for measuring whether an index is sufficiently liquid, Reliant cautioned that bid/ask spread cannot be used as a stand-alone criterion. Reliant added that spreads are a function of, among other things, the underlying volatility of the commodity, the anticipated holding period, and interest rates, and that it is therefore possible for the bid/ask spread to be relatively large due to one of these underlying variables and yet, the market is not necessarily liquid.

Entergy acknowledged that natural gas is not a perfect indicator of electricity costs and that it supports the use of a mature, liquid electricity commodity index. However, Entergy argued that given real world constraints and existing market conditions, continued use of the NYMEX gas index to adjust the price to beat fuel factor is appropriate at this time. Entergy stated that it would be difficult to define, in advance, specific objective criteria that could indicate exactly when the switch from the NYMEX gas index to an electricity index or trading hub should occur. Entergy commented that the commission should also recognize the difficulty in setting prescribed measures of liquidity for the non-ERCOT portion of Texas as the Regional Transmission Organizations and the spot markets continue to evolve, and that, at this time, it would be premature to establish specific criteria on which to judge the liquidity of future electricity markets.

TXU argued that it is too early to move to an electricity index and stated that determining what constitutes a "sufficiently liquid" index is more an art than a science. TXU commented that when looking to see if a viable market index exists, the commission should look only to a settled forward index (an index that is based upon actual settled trades, such as the NYMEX Henry Hub price for natural gas) as opposed to a reported index that is dependent upon calls made to marketing companies inquiring as to the trades that they have made. TXU recommended that rather than predetermining the criteria for selecting an index, the commission should periodically solicit comments from interested parties concerning the development of a promising index or hub.

In reply comments, Houston agreed that there are not any recognized objective standards that currently exist that could be used to define a sufficiently liquid electricity commodity index or trading hub for use in determining future price to beat fuel factor adjustments for all utilities, but stated that this should not prevent the affiliated REPs from meeting their statutory burden to establish a significant increase in the market price of purchased energy, as there are other means to assess the reasonableness of an application to increase price to beat fuel factors based on alleged increases in market prices of purchased energy.

Houston argued that the commission should not decide this issue or whether there are other reasonable methods to determine the market price of purchased energy in this rulemaking and instead leave this issue open for consideration in all future price to beat fuel factor cases. Houston also urged the commission to require all applicants to present direct testimony in each fuel factor adjustment case demonstrating why such a commodity index does or does not exist. In reply comments, Reliant argued that the commission should reject Houston's recommendation because they stated that it is essentially rulemaking "on the fly," and confuses the fuel factor adjustment contested case proceedings with a rulemaking. Reliant added that Houston's suggestion would require an affiliated REP to prove in each contested case proceeding that the rule under which the application was filed is appropriate. Reliant offered that if any market participant believes that a sufficiently liquid electricity commodity index exists, the appropriate action is to request that the commission consider an amendment to the rule, which would then be applied prospectively.

OPC and Cities stated that before a market can be considered liquid, there should exist a framework for the verification of trading prices, and a public entity (i.e. NYMEX, NASD, NYSE) that operates a transparent market in the commodity. OPC and Cities argued that until these threshold issues are met, the commission would be unwise to consider establishment of criteria related to liquidity. In reply comments, Consumer Groups supported the positions of OPC and Cities.

The commission generally agrees with the parties that suggested that it is inappropriate at this time to attempt to adopt specific standards for what would constitute a "sufficiently liquid" electricity commodity index. The commission instead believes it most appropriate for a party that believes a sufficiently liquid index or trading hub exists to make a separate filing under subsection (g)(1)(F) demonstrating that such an index or hub in fact exists and can be relied upon for purposes of making price to beat fuel factor adjustments. Accordingly, the commission rejects Houston's proposal to require affiliated REPs to address this issue in each and every fuel factor adjustment proceeding as unnecessary and an inefficient use of those proceedings. The commission also finds it appropriate to clarify that the relevant prices to be used for fuel factor adjustments are futures prices, not historical prices and amends subsection (g)(1)(F) accordingly.

The commission does agree that certain of the recommended standards are appropriate for parties to consider, in such a filing; specifically, that the index or price be published, verifiable, and independently reported, that the index exhibit significant trading volume, and have a reasonable period of published price history. At this time, the commission also agrees with TXU that the index should be based on actual settled trades as opposed to a reported index that is dependent upon calls made to reporting agencies by brokers or traders, and with OPC and Cities that a verification of reported prices and trades by an independent entity is crucial.

For example, the commission notes that Platts Megawatt Daily currently publishes a "long term forward assessment" which provides for some information regarding futures electricity prices for ERCOT. Platts' description of how it computes prices is located at http://www.platts.com/electricpower/oct28notice.shtml. Specifically for forward prices, Platts' description indicates:

> Platts' assessments of daily forward trading at 16 hubs have always been based on informed judgment by editors and reporters, based on all available data, including reported transactions and all other available information, such as bids and offers, prices at other hubs, and other market dynamics. Platts will continue to assess these daily forward markets, despite their lack of liquidity, because it believes the market values an independent third-party benchmark for these markets.

This statement illustrates the concern the commission has in adopting an electricity price index based on reported prices. While the commission acknowledges that Platts has recently adopted more stringent procedures and verifications as to reported prices, the commission remains concerned about permitting adjustments based on indices where "informed judgment by editors and reporters" and the use of "bids and offers, prices at other hubs, and other market dynamics" have the potential to skew the index from actual market prices.

However, the commission does not necessarily foreclose that a reporting agency can develop a sufficient verification system, but believes the ultimate burden of showing such an index is sufficiently liquid and trustworthy will be higher than an exchange or index based on actual trades.

General Comments on PUC Substantive Rule §25.41

Reliant commented that the current rule has worked as intended and that revisions are unnecessary.

In general, Houston and OPC and Cities argued that the current rule and many of the proposed amendments erode the initial 6.0% rate cut provided by Senate Bill 7. They argued that PURA §39.202(p) places an absolute limit on the level the price to beat may reach which is the level of rates charged by the affiliated electric utility on September 1, 1999, adjusted to reflect the bundled electric utility's final December 31, 2001 fuel factor. They suggested that the price to beat is intended to be a "safe harbor" for rates, not a mechanism to increase prices to ensure that competitors could succeed in the competitive market at the expense of consumers.

AEP REPs, Reliant, Entergy, and TXU disagreed with Houston and OPC and Cities that the current rule violates the provisions of PURA. AEP REPs, in reply comments, argued that the commission has previously rejected these arguments concerning the interpretation of PURA §39.202(l) when the price to beat rule was initially adopted and again when the commission decided the first round of price to beat fuel factor cases in 2002. AEP REPs noted that the preamble and comments to the initial rulemaking and the briefing in the first round of cases address and support the appropriateness of the price to beat fuel factor rule in its present form. AEP REPs and Reliant argued that the price to beat was never intended to be a cost-based escape from a market-based customer choice market that was found by the Legislature to have significant benefits. Instead, AEP REPs argued that the price to beat was meant to support the transition to a fully competitive market. To support their argument, AEP REPs point out that the price to beat protects customers in rural areas where competitive retailers might not initially offer their products because of low customer density. Reliant added that the price to beat was never intended to offer customers a below-market price. Additionally, Reliant stated, customers are free to choose another REP at any time and that any difference between the price to beat and market prices will be captured in the retail clawback at the time of the true-up.

TXU, in reply comments, responded that PURA §39.202(p) applies only to base rates, in that it continues to include an exception so that fuel factors can be adjusted. Further, TXU and ARM argued that the provisions of PURA §39.202(p) apply only with respect to a request made under that provision to increase the price to beat due to a lack of financial integrity. Thus, TXU stated, the restriction on increasing base rates applies only to a financial integrity application made pursuant to PURA §39.202(p). It does not apply to adjustments to the price to beat made pursuant to PURA §39.202(k), which allows the commission to adjust the price to beat after the 2004 true-up and contains no explicit restrictions thereon; nor does it apply to requests by the affiliated REP to adjust the price to beat fuel factor made pursuant to PURA §39.202(l). Entergy stated that it is clear that the cited language does not apply to fuel factors. Entergy argued that the term "safe harbor" refers only to the fact that, with a price to beat, customers are not forced to pay more than that price to beat unless they choose to do so.

The commission disagrees that the current rule violates PURA for the reasons detailed in the Order Adopting §25.41, Relating to Price to Beat, and notes the original rule was not challenged by OPC, Cities, or Houston as unlawful as they could have done under PURA §31.001(f).

The commission also disagrees that PURA §39.202(p) provides for an absolute cap on the price to beat in all circumstances. The commission agrees with TXU and ARM that the provisions of PURA §39.202(p) only apply in the case of a filing by an affiliated REP due to financial integrity reasons and these provisions are intended to apply only to the non-fuel factor portions of the rate. The commission believes that PURA §39.202(p) must be construed with PURA §39.202(a), (b), and (l). That is, an adjustment due to financial integrity reasons must result in rates that are no higher than those in effect on September 1, 1999, as adjusted for the fuel factor set as of December 31, 2002, but that also reflects any adjustments to that fuel factor that have subsequently been made under PURA §39.202(l). OPC and Cities' interpretation could lead to a circumstance that an affiliated REP requests an adjustment due to financial integrity reasons, but ends up with an overall rate that is *lower* that that which existed before the financial integrity adjustment. Such a result appears to be inconsistent with the allowance for an affiliated REP to increase its rate if needed to sustain its financial integrity.

The commission does agree that the price to beat was intended to be a safe harbor for customers, and believes that that intent has been fulfilled by enabling any customer eligible for price to beat service to continue to receive service under the price to beat or return to price to beat service after having selected another REP, and that no eligible customer will pay more than price to beat service unless they so choose. The commission finds that this is consistent with the discussion cited by OPC between Representative Wolens and Representative Williams during the floor debate on Senate Bill 7 in the Texas House of Representatives.

> REP. WOLENS: "This will be a safe harbor for rates. They will be able to spend more money. Customers will be able to spend more money than the price to beat for green power, for example, if they want to. It will be their option. But it will always be a safe harbor that a customer will be able to pay this rate through '07."

> REP. WILLIAMS: "So you're telling me that any ratepayers — anyone who is getting their electricity through a meter, whether it's a residential customers, a small business customer, or a large business customer, will not pay a price higher than the price to beat unless it's their choice to do so?"

> REP. WOLENS: "That is – I will be even more specific on the details if you would like. This applies to residential owners. It applies to businesses, and it applies to small commercials. And it applies in the deregulated areas, and yes, I am saying that there are certain exceptions. One exception would be for an increase in fuel as that would have to be approved by the PUC. So subject to an increase in fuel, that would have to be approved at a hearing before the PUC, I agree with what you just said."

Nowhere in the discussion cited by OPC is any suggestion that the price to beat would not be adjusted if natural gas or purchased energy costs changed; in fact, just the opposite was discussed. The commission finds that Legislature very clearly expected and intended that the price to beat remain an above market rate as illustrated by the following:

1. PURA §39.001 specifies the Legislature's policy and purpose for implementing Senate Bill 7. Specifically, the legislature found that it was appropriate to establish a "competitive retail electric market that allows each retail customer to choose the customer's provider of electricity and that encourages full and fair competition among all providers of electricity" (See PURA §39.001(b)(1)). This indicates that the Legislature intended that new competitors would be able to enter the marketplace and effectively compete for retail customers. This cannot happen if the price to beat becomes a below market rate.

2. PURA §39.202(e) prohibits the affiliated REP from offering other products and services to retail customers than the price to beat for the earlier of 36 months, or when they lose 40% of their residential and small commercial customers. This illustrates the desire of the Legislature to give new competitors three years to acquire customers and establish a foothold in the marketplace by restricting the ability of the affiliated REP to respond to competitive pressures by severely reducing its prices. Again, this cannot happen if the price to beat becomes a below-market rate for a sustained period of time. This is supported by Representative Wolens' statement that:

"If you want competition, they (competitors) have got to come in, and they got to have headroom to be able to come in and price.

"When you think about what goes on with American Airlines, every time American Airlines has had competition, they will rush in. They will lower their price immediately. Sometimes they go underneath the competition. They drive competition out of business. Competition goes away, and then American Airlines is back with higher rates. It happens in every industry.

"And what this is generally going to say is the utility has got to hold their rate here, and we are going to give competitors an opportunity through '05 to come in right here. They've got to come in and compete. They will have the opportunity to come in during this time period and compete unless, unless, one thing happens:

the incumbent has lost 40% of the market. We say that as a matter of market power, if the incumbent loses 40 percent of their customers, competition begins, and then they can lower their price."

3. PURA §39.202(l) provides that the affiliated REP may request up to two adjustments per year to the fuel factor portion of the rate if they demonstrate that the existing fuel factor does not adequately reflect significant changes in the market price of natural gas and purchased energy used to serve retail customers. Notably, this provision does not refer to the actual costs incurred by the affiliated REP to serve retail customer; it refers instead to the market price of natural gas and purchased energy. This provision recognizes that, from the perspective of a new entrant into the marketplace, market prices are what will dictate its ability to compete for service to the retail customer. Again, this supports an interpretation that the Legislature intended that the price to beat remain an above market rate for new entrants. While PURA §39.202(l) does not appear to limit the ability of the affiliated REP to request a downward adjustment to the price to beat fuel factor, it does condition such requests on a showing that a significant decline in natural gas and purchased energy prices has occurred. If that has occurred, it is less likely that a downward adjustment would eliminate the ability of new entrants to continue to economically compete to serve retail customers.

4. PURA §39.262(e) requires the affiliated REP to refund the difference between the price to beat and the prevailing market price of electricity (subject to certain limitations) at the

time of the true-up proceedings. This further indicates an expectation and intention that the price to beat would be an above market rate. In fact, PURA §39.262(e) provides for a cap on the amount required to be refunded, indicating that the Legislature acknowledged that the price to beat could be substantially above market.

While the commission believes that these provisions of PURA, combined with the discussion during the House floor debate on Senate Bill 7 supports that the Legislature intended and expected that the price to beat be an above market rate, the commission notes that the Legislature did not guarantee that would be the case. The Legislature clearly prescribed the composition of the initial price to beat as 6.0% less than the rates in effect on January 1, 1999, adjusted for a final fuel factor. The Legislature then provided for an adjustment mechanism to enable the fuel factor portion of the rate to be adjusted based on changes in market conditions. The Legislature also provided for an adjustment to the base rate portion of the price to beat through the financial integrity test contained in PURA §39.202(p). Notwithstanding all of these provisions and the commission's rules further defining these provisions, it remains possible that the price to beat in some areas may at some point become a below market rate. However, the commission believes that the rule provisions adopted both in the original rulemaking relating to price to beat as well as the amendments to the rule provided for herein provide reasonable means to best accomplish the Legislature's goals of a robust competitive retail marketplace, within the other constraints of the statute.

OPC and Cities argued that under the rule, there is no practical way the price to beat could be reduced, even if natural gas prices dropped significantly, because an application for an increase in the price to beat must be approved. Even the proposed amendments to subsection (g)(3)(A), they argued, would only apply many months after an excessive price to beat had been in effect.

TXU, in reply comments, responded that the affiliate REP can petition to lower the price to beat fuel factor as long as the reduction meets the significance threshold in the rule. FCP argued that while it may be true that there is potential for an affiliated REP to get windfall profits if gas prices decrease after a fuel factor increase is granted, competitive market forces mitigate that potential by penalizing affiliated REPs that are slow to react to decreasing prices.

OPC and Cities suggested that the rule be amended to make all price changes temporary, and to require that the price to beat fuel factors revert back to the January 1, 2002 level at the end of each calendar year. TXU, in reply comments, responded that this suggestion is inconsistent with the statute, which in no way implies, let alone explicitly states, that this is allowed. Further, TXU argued that this would amount to a regulatory method to change the price to beat, which is contrary to the requirements in PURA §39.001(d) that the commission use "competitive rather than regulatory methods… so as to impose the least impact on competition."

The commission agrees with TXU that the affiliated REP does have the right to request a downward adjustment to the price to beat if the significance thresholds in the rule are met and makes clarifying revisions to subsection (g)(1) and subsection (g)(1)(D) to clarify this provision.

The commission notes that since the first set of requests by the affiliated REPs to adjust their fuel factors was approved at the end of August 2002, natural gas prices have consistently risen, and there have not yet been any opportunities for an affiliated REP to request a decrease to their fuel factors. The commission agrees with FCP that customers can, in all areas open to competition, avoid seeing some or all of the price increase requested by the affiliated REP by switching to another REP. Additionally, the commission has added an additional protection for retail customers in the revised rule because, if natural gas prices fall prior to the true-up and the affiliated REP does not request a downward adjustment to the fuel factor, new subsection (g)(3)(A) would result in a downward adjustment to the fuel factor. The commission believes that these provisions of the rule, combined with the right of customers to select service from a non-affiliated REP provide a reasonable implementation of the Legislature's goal of successful retail competition.

The commission disagrees with OPC and Cities' suggestion that the fuel factor adjustments be made temporary. As previously stated in the Order Adopting §25.41 Relating to Price to Beat, while PURA apparently does not prohibit the commission from imposing this requirement, the commission again concludes that such a limitation is unreasonable and unnecessary. This proposal would add an additional layer of uncertainty into the marketplace as the fuel factor would be re-set every January, irrespective of whether or not market prices remained high. An affiliated REP could then immediately request an adjustment that would return the fuel factor to a level comparable to where it had been prior to the re-setting of the factor. In this circumstance, OPC and Cities' proposal would effectively only permit the affiliated REP to make one adjustment per year, making it significantly more difficult for the fuel factor to continue to reflect changes in the cost of natural gas and purchased energy.

As stated in the order adopting the original rule, the fact that affiliated REPs may only make two adjustments per year should guard against unnecessary adjustments, and an affiliated REP that fails to timely request a downward adjustment to the fuel factor will lose customers to other REPs. The commission notes that three affiliated REPs used only one adjustment in 2002, even when the existing rule would have permitted a second adjustment. In the case of those REPs, OPC and Cities proposal would have likely lead those REPs to request an adjustment to their fuel factors in January 2003, and may have resulted in a higher rate than the customers actually paid during January and February 2003. The commission believes that OPC and Cities' proposal would create unnecessary and costly proceedings. The commission therefore declines to make the requested change.

Subsection (c)(9)(B)

TXU suggested revising the definition of representative power price in subsection (c)(9)(B). TXU proposed that the term "by the affiliated PGC" be added at the end of the first sentence to clarify that the capacity auctions being referred to are the ones conducted by the REP's affiliated power generation company. TXU Energy also noted that the word "PURA" should be deleted, as §25.381 is one of the commission's Substantive Rules, not a provision of PURA. TXU commented that the commission should amend the proposed last sentence of subsection (c)(9)(B) to clarify the time period for the equivalent products. Reliant offered a similar suggestion and further proposed that the commission amend this definition to maintain consistency with the methodology used to determine initial headroom and replicate the original capacity auction. TXU similarly suggested that "the most recent aggregated forward 12 months of entitlements" in the second sentence of subsection (c)(9)(B) be amended to clarify exactly what this alternative is and how it would work, as well as whether it is the affiliated REP or the commission that decides whether or not the alternative is to be used in making the price calculation.

The commission agrees with TXU's proposed deletion of the word "PURA" in this subsection and makes the corresponding change. The commission also agrees with the other clarifying language recommended by TXU and Reliant and amends the rule accordingly.

Subsection (c)(11)

Reliant suggested that language be added to the definition of "small commercial customer" in subsection (c)(11) to clarify that for purposes of the threshold targets in subsection (i), unmetered guard and security lights are not considered small commercial customers unless such an account has historically been treated as a separate customer for billing purposes.

The commission agrees with Reliant and makes the requested clarification.

Subsection (g)(1)(A)

Reliant requested that the language regarding the use of the *Wall Street Journal* be clarified due to recent changes in that newspaper's policy regarding publication of Henry Hub natural gas prices.

The commission concurs with the need for clarification, and revises subsection (g)(1)(A) to state, "…,as reported by the Wall Street Journal (either in print or on-line)."

Subsection (g)(1)(A) and (B)

TXU, ARM, AEP REPs, Reliant, and FCP opposed the proposed amendments in subsection (g)(1)(A) and (B) to increase the number of days upon which the average price is calculated from ten days to 20 days. ARM commented that the commission's proposed amendments to the price to beat rule appropriately do not change the fundamental market-based approach embodied in the current rule for adjusting the fuel factor component of the price to beat pursuant to PURA §39.202(l). ARM argued that those amendments, however, are unnecessary because the ten-day rolling average captures true trends in gas prices, while allowing adjustments to the fuel factor to better reflect changing market conditions and assist REPs in hedging their purchases.

TXU suggested that a 15 trading-day period would still meet the commission's objectives without unduly extending the time it takes to implement a fuel factor change. OPC and Cities point out that 15 days is little different from ten or 20 days, by TXU's own admission.

As discussed in the response to comments filed in response to preamble question number one, the commission disagrees with TXU that it is appropriate to adopt a 15 trading-day average, and instead adopts a 20 trading-day average.

In contrast, Reliant proposed a two-day average be adopted. Using a longer time period, Reliant argued, results in an administratively-determined price to beat adjustment rather than a market-based price adjustment. Furthermore, according to Reliant, hedging a rolling average gas price much beyond a one-day average would assume that the affiliated REP could accurately predict the day the price to beat fuel factor adjustment triggers would be met. Similarly, Reliant stated, this would presume that an affiliated REP could accurately predict in advance when the required threshold would be met at the end of a specific 20-day period. Because this is impossible, Reliant concluded that hedging becomes increasingly less likely as the rolling average time period increases.

The commission declines to adopt Reliant's change. Use of a 20 trading-day average will continue to ensure that real trends in the market price for natural gas and purchased energy are captured as opposed to the often temporary volatility that would result from use of a two-day average.

OPC and Cities suggested that a minimum 90-day trading period be used to calculate an average price to serve as a basis for changes to the price to beat fuel factor. TXU, in reply comments, opposed these suggestions because they said it would put all REPs at great financial risk during the interim, and would ensure that retail prices do not timely reflect wholesale prices. Further, TXU argued, such an extended period would make it very difficult, if not impossible, to manage price risks by hedging.

Houston suggested at least a 60-day average and argued that an affiliated REP could still file an application to amend its fuel factor based on a 20-day trading day average and continue to file updated filings to include the new NYMEX forward prices for each day after the case has been filed up until it is decided. If the updated index falls below the materiality threshold, the case would then be dismissed. In reply comments, Houston stated that a ten-day or 20-day standard is insufficient to demonstrate that the change in prices in permanent, a demonstration made necessary by the fact that the rule only contemplates price increases. Houston pointed out that only affiliated REPs are given the power in this rule to change prices; consumers have no way to bring prices down. Houston argued that its proposal does not increase the lag between price change in the gas market and the increase in the fuel factor by using the administrative lag time as the majority of the additional days.

In reply comments, TXU, Entergy, Reliant, and AEP REPs argued that proposals to require a longer averaging period, more than 60 days to more than 90 days, should be rejected. First, TXU argued that the commission may act before 40 days has passed, as it just did in the Reliant case. Second, TXU stated that the affiliated REP has the right to file for an adjustment of its choosing, not what might simply come to pass 40 days after it files. And, while notice is not required, TXU stated that affiliated REPs have been giving notice, and they argued that it would be impossible to provide customers with notice as to what change is being requested, as that would not be known until just before the case is decided by the commission. Houston replied that Reliant and TXU do not provide any solution to the risk that a ten-day average would capture a temporary spike in prices. Houston observed that since gas and electric prices are not correlated, using the 60-day average at least tempers the reliance on NYMEX until a true electric index is developed.

AEP REPs stated that such long averaging periods ignore the balancing of competing objectives that resulted in the rule in its present form and that no new evidence suggests that it is necessary to lengthen the averaging period. Specifically, AEP REPs stated that the commission concluded in the initial rulemaking that there needs to be a short timeline between a significant change in prices and the adjustment of fuel factors so that affiliated REPs are encouraged to hedge their risk of higher fuel prices. Reliant offered similar comments, stating that it would be impossible for an affiliated REP to hedge a 90-day average gas price.

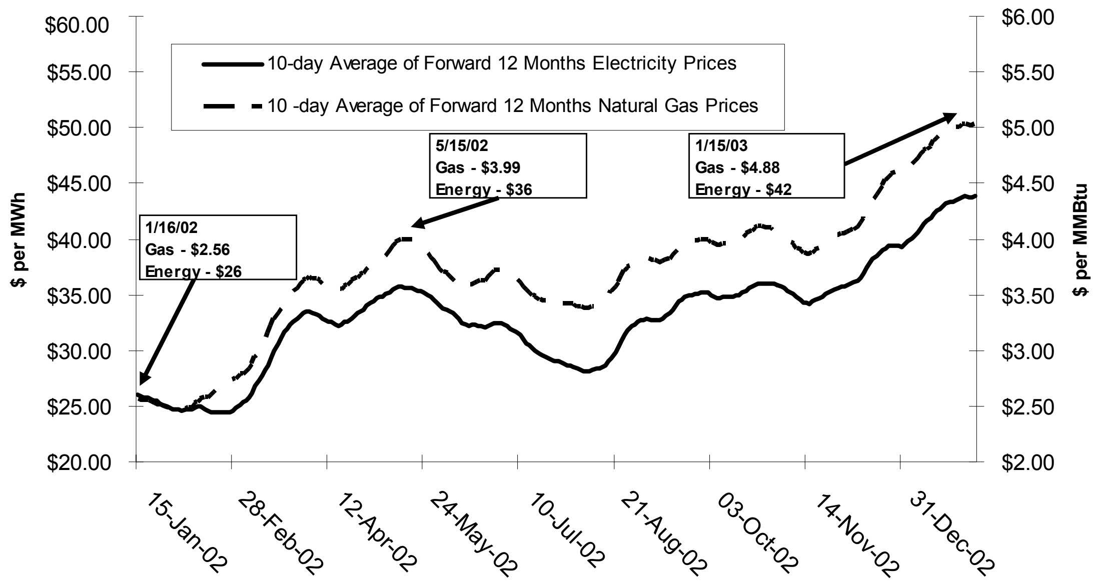
The commission agrees with those commenters who recommend that the use of a 60-day to 90-day average should be rejected. As discussed earlier, the longer the period of time used to average market prices, the greater the potential that the average will be significantly different than the realities of the marketplace because of the lag involved in averaging over so many days. The commission finds that the use of a 20-day average best balances the need to ensure that changes in market prices are real trends and not transitory changes while still permitting the price to beat to remain in line with true market prices.

The commission disagrees with Houston that the market price of natural gas and the market price of electricity in ERCOT are uncorrelated. In fact, forward natural gas prices compared to forward electric prices for the comparable period of time in ERCOT indicates a very strong correlation, as would be expected due to the fact that natural gas fired generation is the marginal unit in virtually all hours of the year, and therefore sets the market price. This is demonstrated by the capacity auction prices provided by Reliant in its reply comments.

Capacity Auction Conclusion Date	Auction Period Average NYMEX 1-YR Strip Gas Price ($/MMBtu)	1-YR Strip Baseload Capacity Auction Price for Houston Delivery ($/MWh)
September 19, 2001	**3.17**	**24.57**
October 17, 2002	**4.04**	**30.67**
Percent Increase	**27%**	**25%**

Additionally, an analysis of natural gas futures prices and forward ERCOT energy prices taken from Platts' MegaWatt Daily also indicates a very strong correlation. While the commission has expressed concerns about use of the Platts forward assessment for purposes of adjusting the fuel factor, the data is currently the best available with respect to forward prices for energy in ERCOT, and therefore can be viewed as indicative of the marketplace when analyzed over a long period of time. The forward prices from the capacity auctions, and the other available data from Platts together demonstrate the correlation between natural gas and energy prices.

Comparison of Natural Gas and ERCOT Electricity Futures Prices



The commission disagrees with Houston that consumers have no means to lower their cost of electricity. The commission notes that the annual rate comparison of the offers available by other REPs as of January 2003, located on the commission's web site at http://www.puc.state.tx.us/electric/rates/RES_avgrate/Jan03rates.pdf, shows that residential customers in all areas of the state have numerous options of REPs who are in some cases offering savings in excess of 10% on an annual basis.

The State and OPC and Cities argued that the rule should require an affiliated REP to demonstrate that its existing fuel factor does not adequately reflect the significant changes in the price of natural gas and purchased energy used to serve retail customers. Then, the State, and OPC and Cities argued that an affiliated REP must demonstrate that the market price of natural gas and purchased energy it is using has changed significantly since the initial fuel factor was set. The State suggested that the NYMEX trading index should not be used at all because it does not reflect the prices an affiliated REP has paid for energy purchased to serve retail customers. TXU responded, in reply comments that PURA §39.202(l) looks only to whether the existing fuel factor adequately reflects significant changes in the market price of natural gas and purchased energy used to serve retail customers, not whether a profit is being earned or whether the REP has incurred losses. TXU and ARM argued that PURA §39.202(l) inquires only as to whether the existing fuel factor adequately reflects the changes in market prices. Finally, TXU argued that there is no direction in PURA §39.202(l) to examine the costs, revenues, load, or generation mix of the affiliated REP. ARM suggested that such a cost-based approach would not serve legislative intent, and would rather reflect a return to a regulatory paradigm. ARM argued that such proof would require a lengthy and complicated proceeding, creating an unreasonable lag between changes in the market price of natural gas and implementation of the adjustment.

Consumer groups argued that using only gas prices results in a price to beat fuel factor which overstates the actual cost of fuel and purchased power. Houston and OPC and Cities argued that the rule should be amended so that natural gas fuel factor adjustments based on a significant change in natural gas should only be applied to the portion of the initial fuel factor, which was subject to the October 1, 2001 gas price update, not on costs associated with non-gas fired generation. OPC and Cities argued that a substantial portion of embedded generation in Texas is comprised of power plants which use coal, lignite, or uranium as the fuel source. OPC and Cities further stated that basing a price to beat fuel factor change on natural gas prices exaggerates the impact of gas prices upon power market prices. Houston, OPC and Cities stated that ERCOT power prices are poorly correlated with gas price changes and that the level and range of power prices within ERCOT support the notion that coal and nuclear plants exert a depressing effect upon power prices. Further, they argued, the adjustment mechanism should be consistent with the framework of the initial fuel factor. The fuel factor is based upon average cost, not marginal cost, they said, and changing that premise would imply other changes to the fuel factor, such as reflecting the more efficient heat rates of new merchant gas plants. The State argues that the problem of fuel factor increases not reflecting fuel mix is one that the commission represented as being fixed in this rulemaking in comments to the Legislature.

TXU and Reliant opposed the suggestion that adjustments to the price to beat fuel factor should take into account the fuel mix of the generation purchased by the affiliated REP. Reliant and TXU argued that REPs do not own generation resources, and therefore there is no gas generation portion of the price to beat fuel factor. Further, Reliant and TXU argued that market prices are determined by the price of the incremental, or marginal, unit of production and in Texas, the marginal unit is gas-fired. Therefore, Reliant concluded, power prices in Texas are driven by the price of natural gas regardless of the type of fuel used in purchased energy. In essence, trading in the ERCOT market today is done based upon a given heat rate and gas price. TXU stated that even if the electricity is in fact generated by a lignite or nuclear plant, the wholesale market price is based upon heat rate and gas prices. TXU and Reliant, in reply comments, responded that this issue was carefully considered by the commission when it adopted the current rule. In deciding how to determine the price changes in purchased energy and natural gas, TXU pointed out that the commission chose to use a gas index both to represent the change in gas prices and as a proxy for an electricity index because: (1) an electricity price index did not exist; and (2) the market price of electricity will likely be set by gas-fired generation.

Reliant disagreed with OPC and Cities' claim that ERCOT power prices are poorly correlated with natural gas prices. Reliant pointed out that the claim is based upon a comparison of NYMEX forward prices to ERCOT spot prices, which Reliant argued is meaningless because it does not compare similar products. Instead, Reliant argued, NYMEX forward natural gas prices are highly correlated, at 96%, to ERCOT forward power prices over the same period.

Reliant also opposed the argument that increased natural gas prices is not enough to satisfy the requirements of PURA §39.202(l). Reliant argued that the commission has the discretion and expertise to determine that the price for natural gas is sufficiently correlated to the price of electricity to act as a proxy when implementing PURA §39.202. Reliant pointed out that the commission has already determined that because the price of wholesale power will be set by gas-fired generation and a sufficiently liquid electricity commodity index does not exist, it is appropriate to use the natural gas price changes in the NYMEX index to the entire fuel factor.

The commission disagrees with the comments of the State, Houston, and OPC and Cities that suggest that fuel factor adjustments should, in fact, become a review of all of the power contracts actually executed by the affiliated REP or should result in an adjustment of only a portion of the fuel factor for changes in natural gas prices. The commission disagrees that examining whether or not there have been "significant changes in the market price of natural gas and purchased energy used to serve retail customers" should be interpreted as something other than an examination of current market prices for natural gas and purchased energy. As the commission found in the original order adopting the price to beat rule, natural gas fired generation is the marginal unit dispatched in most hours of the year in Texas, and therefore will set the market price of electricity. REPs cannot, by law, own generation resources and therefore must buy all of their power in the marketplace. The initial price to beat fuel factors approved in December 2001 were based on the fuel mix of the electric utility; however, since a REP is not a utility, there is no basis in law to review the generation purchase contracts for an affiliated REP as part of a fuel factor adjustment request. The commission concurs with TXU that irrespective of whether that power is in fact generated by a nuclear or coal generation unit, it will be priced in the marketplace based on the price of the marginal unit, which is gas fired. It is true that as gas prices increase, coal and nuclear generated power may not cost any more to generate, and the owners of those plants will realize increased profits. However, the owners of those plants are not REPs, affiliated or otherwise.

Furthermore, the commission is concerned that if actual contracts of the affiliated REPs are examined and the contracts are in fact tied to changes in natural gas prices, then parties will next attempt to argue that those contracts were not prudent, and the affiliated REPs should have instead entered into different types of contracts, such as fixed price contracts. Fuel factor adjustment proceedings would then become not only "fuel reconciliation" type proceedings where actual costs are examined, but also prudency reviews. Such costly, lengthy, and unnecessary proceedings are not contemplated in PURA, and would be contrary to the directive in PURA §39.001(d) that the goals of Senate Bill 7 are to be achieved using "competitive rather than regulatory methods" and that rules adopted to implement Senate Bill 7 must be "limited so as to impose the least impact on competition."

Moreover, the arguments made by OPC and Cities and State ignore the fact that new entrants seeking to acquire retail customers will most certainly need to buy all of their power needs from the marketplace. Basing price to beat fuel factor adjustments solely on the actual costs of the affiliated REP and not the market price of natural gas and purchased energy (as required by statute) will ignore the market prices that non-affiliated REPs must incur to compete against the affiliated REP. As discussed previously, the Legislature provided clear indication that it expected there to be adequate headroom under the price to beat for new entrants to be able to effectively compete, and that the price to beat could be adjusted in response to changes in market prices, not the specific costs of a specific REP. Tying price to beat fuel factor adjustments solely to the costs of the affiliated REP would arguably conflict with the directive in PURA §39.001(c) that the commission "may not make rules…(that) discriminate against any participant or type of participant during the transition to a competitive market and in the competitive market."

OPC and Cities, the State, and Houston also fail to acknowledge that although customers always retain the option to take service at the price to beat as a safe harbor, they are not required to do so, and may switch (and in fact, were expected to switch) to competitive offers. The commission also notes that, if natural gas prices fall prior to the true-up proceeding, that the adjustment provided for in subsection (g)(3)(A) will be a smaller decrease under the OPC and Cities' proposal than that contained in the rule.

The available data continues to demonstrate that natural gas prices and electricity prices in ERCOT are significantly correlated, in stark contrast to the assertions to the contrary made by OPC and Cities, State, and Houston. The capacity auction prices cited by Reliant in its reply comments demonstrate a very strong correlation between the two. A comparison of changes in forward natural gas prices and the limited forward electricity prices contained in Platt's MegaWatt Daily also suggest a very high (over 95%) correlation between the two prices.

The commission therefore declines to alter the rule to only adjust a portion of the fuel factor for changes in natural gas prices or to require a reconciliation or review of the actual costs of the affiliated REP and finds that PURA instead requires an examination of the market prices of natural gas and purchased energy. The commission believes that the provisions of the rule that require adjustments to the fuel factor based on the market price of natural gas and purchased energy are reasonable given the requirements of PURA §39.001(c) and (d), §39.202(l), §39.262(e), and the aforementioned floor debate on Senate Bill 7 in the Texas House of Representatives.

OPC and Cities supported the amendment in subsection (g)(1)(A) to require the affiliated REP make its filing the day after the 20 trading-day period upon which it bases its proposed fuel factor change. OPC and Cities stated that this amendment will somewhat reduce the opportunity for "strategic" selection of the rolling average period.

TXU, FCP, and ARM opposed the amendment in subsection (g)(1)(A) to require the affiliated REP make its filing the day after the 20 trading-day period upon which it bases its proposed fuel factor change. FCP argued that this provision is unreasonable because an affiliated REP would be forced to choose a day to file its request and hope that the gas prices are approaching a peak, or the opposite for decreasing gas prices. By contrast, FCP argued, allowing the affiliated REP to identify the point where gas prices have leveled off, as the current rule allows, significantly reduces the risk of divergence between gas prices and the fuel factor. In reply comments, OPC and Cities point out that affiliated REPs have otherwise insisted on using data which is as fresh as possible, and that this one day deadline is more in line with this desire. They also observe that affiliated REPs have full discretion in choosing when to file, so allowing them to select the best ten-day average from a window would institutionalize the ability to "game" the system to the extent of picking the most advantageous time frame. Houston suggests that its 60-day solution would allow a more extended filing window while still protecting against gaming. Houston otherwise opposes a more extended filing window.

In response to OPC and Cities' comments that Reliant's recent filing is proof that REPs have gamed the selection of the rolling average period to "maximize price increases," TXU pointed out that Reliant did not use the highest ten trading-day average it could have used.

TXU and FCP stated that it would be administratively difficult to get the filing prepared in less than one day. ARM noted that the proposed amendment may have the unintended consequence of requiring subsequent amendments to the affiliated REP's petition to correct matters prepared in haste, the effect of which may be to increase, rather than reduce, the lag between the market information used to determine whether the current fuel factor will reflect the market price of natural gas and the affiliated REP's adjustment of its fuel factor based on that information. Instead, TXU suggested that the rule require affiliated REPs to make the filing no later than the third business day after the 20 trading-day period has closed, while FCP suggested that the filing be made within five days. OPC and Cities observed that adjustment applications have thus far been somewhat limited, and that all that would be required on the filing date is updating a few spreadsheets from the Wall Street Journal that morning.

The commission agrees with OPC and Cities that the elimination of the window reduces the potential for an affiliated REP to make a strategic selection of which trading days to use in order to maximize an adjustment request. The commission disagrees with FCP that the affiliated REP should retain the filing window in order to better time a peak in the market. The commission believes that the affiliated REP should retain the risk in choosing when to file for an adjustment, and notes that the current filing window only permits a very limited ability to time a peak in the gas market. The commission appreciates the comments by TXU and FCP regarding the administrative difficulty in preparing a filing in less than one day, and therefore modifies the proposed rule to reflect that the filing should be made no later than the second day after the 20 trading-day period ends.

TXU suggested that the word "business" in subsection (g)(1)(B) should be replaced with the word "trading" to be consistent with the rest of the rule.

The commission agrees and makes the suggested change.

Subsection (g)(1)(C) and (D)

TXU, AEP REPs, Reliant, Entergy, FCP, and ARM all stated that there has been no change in circumstances which would warrant changing the 4.0% threshold from the original rule. AEP REPs pointed out that the 4.0% standard is harmonious with long-standing fuel surcharge rules, and that raising the threshold simultaneously with increasing the number of days averaged significantly reduces the affiliated REPs ability to respond to changing market conditions and alters the balance achieved by the original rule. From AEP REPs' standpoint, if the 4.0% threshold represented significant loss under regulation, when the REP was guaranteed of recovering the loss through the reconciliation process; it surely represents a significant loss under the price to beat, where there is no recovery or reconciliation. AEP REPs argued that affiliated REPs should not be forced to ignore unrecoverable losses when other commission rules require refunds and surcharges for recoverable amounts because it would be inconsistent. ARM pointed out that there is no need to harmonize the price to beat rule's 4.0% threshold with the POLR rule's 5.0% threshold, because POLR fuel factors can be adjusted monthly while price to beat fuel factors can be adjusted only twice per year, making a threshold of 5.0% actually a tougher criteria than the POLR rule's threshold represents. FCP stated that increasing the threshold imposes an additional cost risk for affiliated REPs, which could reduce competition and lower the quality of service to retail customers. AEP REPs suggested that changing the threshold now suggests that the commission lacks confidence that competitive REPs can offer a real alternative for consumers. OPC and Cities stated in reply that they believe that a lack of confidence is justified. OPC and Cities cited the existence of a regulated price to beat as evidence that the Legislature did not have unwavering faith in competitive markets. They also cited the lack of switching by residential and other small customers as evidence that consumers do not see a benefit in having electric choice.

TXU argued that the current 4.0% threshold and the two-times-per-year restriction on requesting changes are redundant — the second renders the first unnecessary. TXU suggested that the higher thresholds could make it difficult for competitive REPs to compete by restricting headroom. It could also make it difficult for affiliated REPs to adjust fuel factors downward in the event of a long term decrease in natural gas prices, especially true if a figure greater than 5.0% were chosen, according to TXU.

The commission finds that it is appropriate to retain the 5.0% threshold. The commission believes that harmonizing this requirement with the POLR rule provides for consistency in the level of natural gas and purchased energy market price changes deemed to be significant by the commission.

The commission disagrees with the suggestion that the Legislature did not have sufficient confidence in competitive markets. This is directly contrary to the Legislature's policy pronouncement in PURA §39.001(a). The commission believes that the Legislature recognized that competition does not develop overnight, and that the public interest was best protected by transitioning customers to a competitive marketplace through the price to beat. As such, the price to beat was created as a safe harbor that customers could return to, but the fuel factor portion of that rate could adjust as market prices changed. The aforementioned discussion of the floor debate in the House of Representatives suggest that the Legislature expected and intended for new entrants to have a period of time to be able to enter the market and successfully compete for customers so that when the price to beat expires totally in 2007, there would be an adequate number of competitors to protect customers from market power abuse.

AEP REPs, FCP, TXU, Reliant, and ARM opposed the higher 10% threshold for fuel factor adjustment requests filed after November 15 in a given calendar year. ARM and FCP claimed that this higher threshold could expose affiliated REPs to significant financial risks. FCP agreed and calculated that an ill-timed rise in natural gas prices could cost them as much as $800,000 due to the six-week delay in implementing an adjustment. ARM, Reliant, TXU, and AEP REPs stated that the definition of the word "significant" does not change late in the year, so there is no justification for raising the standard after November 15. TXU pointed out that changes in natural gas prices near the end of the year are not necessarily transitory, so requests for an adjustment of between 5.0-10% after November 15 are not necessarily abusive. AEP REPs and TXU suggested that this bar actually creates an incentive for claiming a 5.0-10% increase in October or early November. TXU observed that Reliant's most recent filing would have been legal under the new environment. TXU further believed that the 10% threshold is an unnecessary restraint upon the exercise of the affiliated REP's legal rights. ARM argued that had the legislature wished to restrict late year changes; they would have done so when they imposed the two-changes-per-year restriction.

Houston and OPC and Cities suggested that the commission impose a higher threshold, such as 10% or 15% for all fuel factor adjustment requests. Houston argued that 4.0-5.0% changes in natural gas prices are common, and thus not significant. OPC and Cities believed such a higher threshold would be better at deterring unnecessary price changes. Houston, and OPC and Cities stated that the 4.0% standard worked under regulation because consumers were be protected from unnecessary rises in fuel charges by the reconciliation process, which does not exist under the current or proposed rule. The lack of reconciliation requires a higher standard to protect consumers. OPC and Cities, and the State pointed out that the affiliated REPs have never presented evidence that a higher standard would result in actual losses rather than reduced profits for the affiliated REPs, and thus suggested that the commission discount such claims by the affiliated REPs. The State cited statements by affiliated REPs that actual financial cost is irrelevant to fuel factor adjustment as reason to discount the affiliated REPs' claims of potential losses; and described the losses which affiliated REPs claim as reduced windfalls, rather than actual losses. OPC and Cities, the State, and Houston all stated that meeting these thresholds for natural gas prices, whether 4.0% or higher, do not by themselves meet the statutory requirement that a demonstration of an increase in the market price of energy used to serve customers be made. OPC and Cities cited the recent Reliant filing as one that this rulemaking is intended to prevent, and pointed out that even the proposed thresholds would not have prevented it. Houston stated that natural gas traders have already been caught manipulating that market, and that a higher threshold would make it more difficult to game that market to meet the threshold. Houston specifically agreed with the idea of a higher threshold at the end of the year to prevent the utility from capturing a run-up in the natural gas prices.

As stated in the original order adopting the price to beat rule, there are two limitations on the affiliated REP's ability to request adjustments to the fuel factor: (1) the fact that the affiliated REPs may only make two adjustments per year; and (2) the materiality (or significance) thresholds in the rule. It is these limitations that have led the commission to find that it is not reasonable or necessary to make adjustments temporary. However, the first of these limitations becomes less of a restraint toward the end of a calendar year because the risk of requesting an adjustment (in that it uses one of the two-per-year adjustments) is significantly reduced. As a result, the commission finds that a more stringent materiality threshold is in the public interest near the end of a calendar year in order to balance that reduced risk. The commission agrees that this may make affiliated REPs more likely to make a request in October or November for an increase in market prices between 5.0% and 10%, but the affiliated REPs do so at the risk of not being able to request a larger increase later in the year if market price warrant.

The commission disagrees with the statement by Houston implying that recent allegations and admissions regarding potential manipulation of the natural gas market are relevant with respect to the use of NYMEX natural gas prices. In fact, in its *Initial Report on Company Specific Separate Proceedings, and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices,* (Docket Number PA02-2-000, August 2002; The full report can be found on the FERC's website) the Federal Energy Regulatory Commission (FERC) staff did conclude that spot gas price indices for California delivery points may have been manipulated. However, the FERC staff in no way concluded that Henry Hub spot or NYMEX Henry Hub futures prices had been manipulated. To the contrary, FERC staff considered using Henry Hub prices as a substitute for California delivery points because "Henry Hub is the most liquid natural gas market in the country (Docket Number PA-2-2-000, August 2002 at 61) and therefore less susceptible to manipulation. Furthermore, FERC staff found that because NYMEX is a "regulated, organized exchange… required by the CFTC (Commodities Futures Trading Commission), among other things, to maintain and enforce internal auditing mechanisms and to maintain painstakingly detailed records of trading activity," NYMEX markets "play an important role in determining an appropriate benchmark for prices." The FERC report details at length the manner in which NYMEX oversees its commodities market to deter manipulation.

TXU suggested rephrasing subsection (g)(1)(D) to clarify that meeting the threshold fulfills the PURA statutory requirement that it be demonstrated that fuel factors do not reflect significant changes in the market price of electricity and natural gas used to serve customers. ARM agreed with TXU's proposal, and further suggested that subsection (g)(1)(D) use "meets or exceeds

5.0% (or 10% if applicable)" in place of "exceeds 5.0% (or 10% if applicable)", to be harmonious with the threshold of "5.0% or more" from subsection (g)(1)(C).

The commission agrees with the recommendations of ARM and TXU and makes the corresponding clarifications.

Subsection (g)(1)(D)(i) and (ii)

The State supported the amendment in subsection (g)(1)(D)(i) and (ii) to increase flexibility in the processing of an affiliated REP's fuel factor adjustment; but argued that the 45-day deadline has no basis in statute, is unprecedented for a contested case at the commission, and is not consistent with fundamental requirements of due process.

TXU, ARM, Reliant, and FCP opposed the amendment in subsection (g)(1)(D)(i) and (ii) to increase flexibility in the processing of an affiliated REP's fuel factor adjustment. TXU and ARM argued that the 45-day deadline be retained in the rule because the objective is to timely adjust the fuel factor in the price to beat to reflect significant changes in the market price of natural gas and purchased energy. ARM stated that this objective benefits both affiliated REPs, by allowing them to reflect significant changes in the market price of natural gas and purchased energy in the price to beat, and nonaffiliated REPs, by ensuring that headroom is not adversely affected by any significant changes in such a market price.

TXU, in reply comments, argued that it is not only possible to meet a 45-day deadline, but it will be quite practical now that the commission has, through its decisions in the initial round of price to beat fuel factor filings, clearly set out the limited scope of proceedings to change the fuel factor; and has through this rulemaking reaffirmed those decisions. TXU pointed out that Reliant's November 2002 fuel factor request provides proof that proper application of the price to beat rule can readily be accomplished within 45 days, as that case was decided only 36 days after it was filed. AEP REPs agreed, stating that it is reasonable to assume that 45 days provide an adequate period for most price to beat fuel factor change proceedings.

TXU, in reply comments, disagreed with the State's claim that a 45-day deadline constitutes a denial of due process. TXU argued that if the limited scope of a fuel factor filing under the rule is properly observed, then there should be no issue that requires extensive discovery or litigation.

The commission agrees with TXU and others who note that the proceedings contemplated to adjust the fuel factors are limited in scope, and can therefore be performed in a 45-day timelines. The commission notes that the 45-day processing timeline was included in the original price to beat rule, and was not challenged by any party, including the State. The commission believes that, if a fuel factor adjustment is warranted due to increases in the market price of natural gas and purchased energy, that the adjustment should be processed as expeditiously as possible while still providing adequate time to ensure that the adjustment has been made in accordance with the provisions of the rule. The commission does not agree that fuel factor adjustment proceedings should be lengthy and costly proceedings, as the rule adopted by the commission is prescriptive in nature as to how the adjustments should be processed. Because the commission has found that the statute provides for changes to the fuel factor based on changes in the market price of natural gas and purchased energy and found it reasonable to measure those changes in market prices by independent indices (i.e. NYMEX futures market prices), it is unnecessary to expand the scope of fuel factor adjustment proceedings beyond the examination of how the prices in those markets have changed.

TXU, Reliant, and ARM suggested that in those instances where a final order cannot be issued on or before the 45-day deadline, then the rule should specify that the order shall be adopted at the next scheduled Open Meeting held thereafter. In addition, TXU supported including a provision allowing the parties to agree to extend the 45-day deadline, with such an agreement possibly including interim rate relief. FCP proposed that any extension of the 45-day deadline automatically include implementation of interim rate relief.

Houston and OPC and Cities stated that the 45-day time frame is extremely short. However, OPC and Cities argued that the commission does not have any authority to grant interim rate increases and opposed any such amendment in this rule. Houston argued that there is no statutory requirement that the commission decide a fuel factor case in an allotted time frame. Houston suggested that, at a minimum, a 90-day time period be adopted. Further, Houston suggested that the rule allow for a good cause exception to the deadlines set forth in the rule.

The commission declines to make the change suggested by TXU, Reliant, and ARM. While the commission generally concurs with the intent behind the suggested revision, and notes that current fuel factor proceedings are being completed within the 45-day timeline embodied in the current rule, the commission believes it appropriate to retain flexibility in processing the adjustment applications in the event unforeseen circumstances arise.

The commission agrees with Houston that there is no statutory requirement to process fuel factor adjustments in a specific time frame, however, the commission believes that having a defined period of time for processing adjustments to the fuel factor provides certainty to the marketplace, and better allows non-affiliated REPs to respond to fuel factor changes through increased marketing efforts, or revisions to their rates. The commission agrees that there is no explicit authority to grant interim rate relief in fuel factor adjustment proceedings, but notes that the rule only provides for interim relief if agreed to by all of the parties to a fuel factor adjustment proceeding.

Subsection (g)(1)(E)

OPC and Cities stated that the rule should delete any references to headroom and should not allow an affiliated REP to request an adjustment to the fuel factor if headroom decreases as a result of significant changes in the price of purchased energy because, they argued, PURA does not allow for the creation or maintenance of headroom to be a factor in the price to beat. They stated that considering headroom as a factor would create higher prices without any real price competition. They argued that the Legislature intended for ratepayers to save money as the result of the introduction of competition, and that even in cases where financial integrity of competitors was in question, there were limits placed on allowable price increases. They stated that there is nothing in PURA that supports the view that maintaining adequate headroom to ensure the success of unaffiliated competitors was the goal or desire of the legislation.

Entergy replied that OPC and Cities own evidence, an attached transcript of a statement on Senate Bill 7 by Representative Wolens, contradicts OPC and Cities position on headroom. Specifically, Entergy cites a statement by Representative Wolens describing headroom maintenance as being part of the "genius" of the bill.

The commission disagrees with OPC and Cities and Entergy for the reasons previously stated and notes that no change to subsection (g)(1)(E) has been made from the current rule except with respect to the timeframes for the commission to issue a final order in a proceeding brought under this portion of the rule. The commission further notes that no party challenged the validity of this provision when the commission originally adopted §25.41.

Subsection (g)(1)(E)(ii)

TXU suggested that the phrase "or as soon as practicable thereafter" be replaced with the phrase "or at the next Open Meeting held thereafter." TXU also stated that the rule should allow the parties to agree to extend the 60-day deadline, with such an agreement possible including interim rate relief.

The commission declines to make the change suggested by TXU. While the commission generally concurs with the intent behind the suggested revision, the commission believes it appropriate to retain flexibility in processing the adjustment applications in the event unforeseen circumstances arise.

Subsection (g)(1)(F)

TXU recommended that the last portion of the first sentence be modified as follows: "to adjust the fuel factor *to adequately reflect* significant changes in the price of purchased energy." TXU stated that the proposed change uses the statutory language and thus should help to clarify the commission's intent.

The commission concurs with TXU and has made the requested clarification.

AEP REPs and OPC and Cities commented that they do not oppose the changes to subsection (g)(1)(F) to encourage the development of liquid trading hubs, but stated that the proposed amendment would have little practical effect. OPC and Cities recommended that a more reasonable solution would be to require applicants to provide data of actual purchases of gas and electricity used to serve retail customers, which could be collected over time and verified.

The commission believes that the creation of liquid trading hubs can add significant benefits to the competitive retail market by increasing transparency and liquidity in the wholesale market. The commission declines to make the change suggested by OPC and Cities because the reporting of bilateral transactions by market participants is currently being addressed in Project Number 26188, *Rulemaking Proceeding Concerning Disclosure of Information Related to Electricity Transactions Originating or Terminating in Texas.*

Subsection(g)(3)(A)

OPC and Cities supported the proposed amendments to subsection (g)(3)(A) to require a reduction to the price to beat at the time of the true-up if gas prices have declined. They also argued that the rule should require price reductions at any time when gas prices are substantially reduced, not just at the time of true-up. Entergy argues that this is contrary to PURA §39.202(l), which gives the affiliated REP sole right to request a price to beat fuel factor adjustment, other than at true-up.

As previously stated, PURA §39.202(l) vests sole authority to request adjustments to the price to beat fuel factor in the affiliated REP, with the exception of the ability of the commission to adjust the price to beat following the true-up. The commission declines to make the change recommended by OPC and Cities for that reason.

Subsection (g)(3)(B)

ARM and Reliant supported the amendments in subsection (g)(3)(B) to adjust the price to beat base rates to correlate with changes made to non-bypassable charges so that headroom is preserved. ARM further suggested that the rule require the commission to adjust the price to beat to achieve the level of headroom established by the commission at the onset of the competitive retail market and allow the commission to further increase the adjusted price to beat to encourage full and fair competition.

The commission declines to make the change suggested by ARM for the reasons stated in response to the similar comments provided by ARM on question two.

ARM also proposed that the rule require that any adjustments to the price to beat ordered in the true-up proceeding be made to the base rate components of the price to beat on a schedule consistent with the processing of the TDU rate adjustment application pursuant to §25.263(n) of this title. Reliant agreed and suggested that the price to beat be adjusted accordingly with interim rates that may be awarded to TDUs during the lengthy true-up proceedings and that language changes be made to reflect the rule changes they proposed in their answer to Question 2.

The commission declines to make the change suggested by Reliant because PURA §39.202(k) permits the commission to adjust the price to beat *following* the true-up proceedings. While the commission recognizes that interim rate relief may result in an increase to the non-bypassable charges paid by REPs to serve their retail customers, the commission notes that PURA §39.262(j) requires the commission to issue an order within 150 days of the true-up filing, which should limit the exposure of REPs to interim rate relief. The commission believes that the language contained in subsection (g)(3)(B) is consistent with the comments made by ARM.

OPC and Cities did not support the proposed amendments in subsection (g)(3)(B) regarding adjustments of the base rate portion of price to beat to reflect changes in non-bypassable charges after the true-up. OPC and Cities argued that the amendments would allow increases in the price to beat for factors unrelated to changes in prices for gas or electric energy used to serve retail customers. They further argued that it would be unlawful and inequitable for the commission to allow increases in the price to beat for issues such as stranded costs and securitization at the time of the true-up. OPC and Cities stated that the concept of "headroom" is never referenced in Senate Bill 7 and that by including a "headroom adjustment" as part of the true-up, the commission has improperly concluded that stranded cost and/or transition charges determined in the true-up should be flowed through to price to beat customers. OPC and Cities stated that this would result in a double recovery of stranded generation assets from ratepayers since the underlying assets are already included in the January 1, 1999 base rate charges.

Reliant and ARM disagreed with OPC and Cities in reply comments. Reliant argued that the price to beat is not a cost-based rate so there are no cost-based components and therefore the argument about double-recovery is not founded. ARM stated that the concept of "headroom" is a viable one in the context of both the price to beat and any statutorily allowed adjustments to the price to beat. ARM argued that OPC and Cities' argument that this proposed amendment is contrary to PURA §39.202(l) ignores the plain language of PURA §39.202(k) that permits the commission to adjust the price to beat following the true-up proceedings. Finally, ARM stated that the contention that the proposed amendment would result in automatic adjustment to rates without cost support ignores the fact that non-bypassable charges will have a cost basis, as computed in the true-up.

The commission agrees with the comments of ARM and Reliant. The commission finds that it has broad authority under PURA §39.202(k) to adjust the price to beat following the true-up and finds that it is appropriate to provide for an adjustment to reflect changes in non-bypassable charges for the reasons previously stated.

To avoid a perceived discrepancy, ARM proposed that the commission use the word "shall make" rather than "may consider" in the second sentence of subsection (g)(3). ARM stated that such a change would reflect the commission's exercise of discretionary judgment under PURA §39.202(k) that it *shall* make certain adjustments to the price to beat in this future proceeding. ARM argued that this provision also should allow for an upward adjustment to the price to beat fuel factor if the calculated rolling price permits such an adjustment under the criteria of the rule, and if the affiliated REP requests to make such an adjustment. ARM suggested that any such adjustment would count as one of the two requests per year that the affiliated REP may make under PURA §39.202(l).

The commission agrees with the comments of ARM to change the term "may" to "shall" to reflect that the adjustments contemplated in subsection (g)(3) will be made in accordance with the rule provisions. The commission believes that it is appropriate to provide certainty that the adjustments will occur. The commission disagrees, for the reasons previously stated, that the fuel factor should be adjusted upward by the commission if natural gas prices have risen, and notes that the affiliated REP retains the right to make such a request under PURA §39.202(l).

FCP suggested clarifying the last sentence in subsection (g)(3)(B) which now reads, "Each component of the base rates shall be adjusted in the same proportion in complying with this section." TXU and ARM suggested that the commission amend subsection (g)(3)(B) to add the phrase "residential and small commercial price to beat" before the words "base rates" to make it clear that the adjustment is applied to all price to beat components.

The commission concurs with the need for a clarification, but instead revises the last sentence of subsection (g)(3)(B) to state, "Each component of the base rates for each residential price to beat base rate tariff shall be adjusted in the same proportion in complying with this section. Each component of the base rates for each small commercial price to beat base rate tariff shall be adjusted in the same proportion in complying with this section."

This section is adopted under the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2003), 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 PURA §39.202 which establishes the price to beat obligation for affiliated retail electric providers.

Cross Reference to Statutes: PURA §§14.002, 39.202, 39.262.

§25.41. Price to Beat.

(a) **Applicability.** This section applies to all affiliated retail electric providers (REPs) and transmission and distribution utilities, except river authorities. This section does not apply to an electric utility subject to Public Utility Regulatory Act (PURA) §39.102(c) until the end of the utility's rate freeze.

(b) **Purpose**. The purpose of this section is to promote the competitiveness of the retail electric market through the establishment of the price to beat that affiliated REPs must offer to retail customers beginning on January 1, 2002 pursuant to PURA §39.202.

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

(1) **Affiliated electric utility** — The electric utility from which an affiliated REP was unbundled in accordance with PURA §39.051.

(2) **Competitive retailer** — A REP or a municipally owned utility or distribution cooperative that offers customer choice in the restructured competitive electric power market or any other entity authorized to sell electric power and energy at retail in Texas.

(3) **Headroom** — The difference between the average price to beat (in cents per kilowatt hour (kWh)) and the sum of the average non-bypassable charges or credits approved by the commission in a proceeding pursuant to PURA §39.201,

or PURA Subchapter G (in cents per kWh) and the representative power price (in cents per kWh). Headroom may be a positive or negative number. A separate headroom number shall be calculated for the typical residential customer and the typical small commercial customer. The calculation for the typical residential customer shall assume 1,000 kWh per month in usage. The calculation of the typical small commercial customer shall assume 35 kilowatts (kW) of demand and 15,000 kWh per month in usage.

(4) **Nonaffiliated REP** — Any competitive retailer conducting business in a transmission and distribution utility's (TDU's) certificated service territory that is not affiliated with that TDU unless the competitive retailer is a successor in interest to a retail electric provider affiliated with that TDU.

(5) **Peak demand** — The highest 15-minute or 30-minute demand recorded during a 12-month period.

(6) **Price to beat period** — The price to beat period shall be from January 1, 2002 to January 1, 2007. In a power region outside the Electric Reliability Council of Texas (ERCOT) if customer choice is introduced before the date the commission certifies the power region pursuant to PURA §39.152(a) are met, the price to beat period continues, unless changed by the commission in accordance with PURA Chapter 39, until the later of 60 months after the date customer choice is introduced in the power region or the date the commission certifies the power region as a qualified power region.

(7) **Provider of last resort (POLR)** — As defined in §25.43 of this title (relating to Provider of Last Resort).

(8) **Registration agent** — As defined in §25.454 of this title (relating to Rate Reduction Programs).

(9) **Representative power price** — The simple average of the results of:

(A) a request for proposals (RFP) for full-requirements service of 10% of price to beat load for a duration of three years expressed in cents per kWh; and

(B) the price resulting from the capacity auctions of the affiliated power generation company (PGC) required by §25.381 of this title (relating to Capacity Auctions) for baseload capacity entitlements auctioned in the ERCOT zone where the majority of price to beat customers reside, expressed in cents per kWh. The calculation of the price resulting from the capacity auctions shall assume dispatch of 100% of the entitlement and shall use the most recent auction of a 12-month forward strip of entitlements, or the most recent aggregated forward 12 months of entitlements. The affiliated REP, at its option, may conduct an RFP or purchase auction for an amount equivalent to the amount, in MWs, of the affiliated PGC's capacity auction for the September 2001 12-month forward strip baseload entitlements.

(10) **Residential customer** — Retail customers classified as residential by the applicable transmission and distribution utility tariff or, in the absence of classification under a residential rate class, those retail customers that are

primarily end users consuming electricity for personal, family or household purposes and who are not resellers of electricity.

(11) **Small commercial customer** — A non-residential retail customer having a peak demand of 1,000 kilowatts (kW) or less. For purposes of this section, the term small commercial customer refers to a metered point of delivery. Additionally, any non-residential, non-metered point of delivery with peak demand of less than 1,000 kW shall also be considered a small commercial customer. For purposes of subsection (i) of this section, unmetered guard and security lights are not considered small commercial customers unless such an account has historically been treated as a separate customer for billing purposes.

(12) **Transmission and distribution utility** — As defined in §25.5 of this title (relating to Definitions), except for purposes of this section, this term does not include a river authority.

(d) **Price to beat offer.**

(1) Beginning with the first billing cycle of the price to beat period and continuing through the last billing cycle of the price to beat period, an affiliated REP shall make available to residential and small commercial customers of its affiliated transmission and distribution utility rates that, subject to the exception listed in subsection (f)(2)(A) of this section, on a bundled basis, are 6.0% less than the affiliated electric utility's corresponding average residential and small commercial rates that were in effect on January 1, 1999, adjusted to reflect the fuel factor

determined in accordance with subsection (f)(3)(D) of this section and adjusted for any base rate reduction as stipulated to by an electric utility in a proceeding for which a final order had not been issued by January 1, 1999.

(2) Unless specifically required by commission rule, an affiliated REP may only sell electricity to price to beat customers labeled or marketed as "green," "renewable," "interruptible," "experimental," "time of use," "curtailable," or "real time," if and only if such a tariff option existed on January 1, 1999 and only for service under the price to beat rate that was developed from that tariff.

(e) **Eligibility for the price to beat.** The following criteria shall be used in determining eligibility for the price to beat:

(1) **Residential customers.** All current and future residential customers, as defined by this section, shall be eligible for the price to beat rate(s) for which they meet the eligibility criteria in the applicable price to beat tariffs for the duration of the price to beat period. An affiliated REP may not refuse service under the price to beat to a residential customer except as provided by §25.477 of this title (relating to Refusal of Service). An affiliated REP may not require residential customers to enter into service agreements with a term of service as a condition of obtaining service under the price to beat, nor may an affiliated REP provide any inducements to encourage customers to agree to a term of service in conjunction with service under the price to beat.

(2) **Small commercial customers.**

(A) A non-residential customer taking service from the affiliated electric utility on December 31, 2001, shall be considered a small commercial customer under this section and shall be eligible for service under price to beat tariffs if that customer's peak demand during the 12 consecutive months ending on September 30, 2001, does not exceed 1,000 kilowatts (kW). A non-residential customer with a peak demand in excess of 1,000 kW during the 12 months ending September 30, 2001, or during the price to beat period, shall no longer be considered a small commercial customer under this section. However, any non-residential customer whose peak demand does not exceed 1,000 kW for any period of 12 consecutive months after it became ineligible to be a small commercial customer under this section shall be considered a small commercial customer for billing periods going forward for purposes of this section.

(B) All small commercial customers, as defined by this section, shall be eligible for the price to beat rate(s) for which they meet the eligibility criteria in the applicable price to beat tariffs for the duration of the price to beat period. An affiliated REP may not refuse service under the price to beat to a small commercial customer, except as provided by §25.477 of this title. An affiliated REP may not require small commercial customers to enter into service agreements with a term of service as a condition to obtaining service under the price to beat, nor may an affiliated REP provide any inducements to encourage customers to agree to a term of service in conjunction with service under the price to beat.

(f) **Calculation of the price to beat.**

(1) **Rates to be used for price to beat calculation.** The following criteria shall be used in determining the rates to be used for the price to beat calculation.

(A) Residential. A price to beat rate shall be calculated for each rate and service rider under which a residential customer was taking service on January 1, 1999, except as approved by the commission pursuant to subparagraph (C) of this paragraph. A price to beat rate shall not be calculated for any new service or tariff option granted to an affiliated electric utility pursuant to PURA §39.054, or any other rate or tariff option not in effect on January 1, 1999.

(i) Beginning with the first full billing cycle of the price to beat period, residential customers served by the affiliated REP shall be placed on the price to beat rate derived from the rate under which they were taking service on December 31, 2001.

(ii) Beginning with the first full billing cycle of the price to beat period, residential customers served by the affiliated REP who were taking service under a rate for which a price to beat rate was not developed, shall be placed on the price to beat rate derived from any eligible residential rate that was or would have been available to the customer on January 1, 1999.

(iii) New residential customers after December 31, 2001, may choose any price to beat rate for which they meet the eligibility requirements as detailed in the applicable price to beat tariff.

(iv) Residential customers who return to the affiliated REP after being served by a non-affiliated REP may choose any price to beat for which they meet the eligibility requirements as detailed in the applicable price to beat tariff(s).

(v) Notwithstanding clauses (i) – (iv) of this subparagraph, residential customers may request service under any price to beat rate for which they are eligible. Selection of the most advantageous rate shall be the sole responsibility of the residential customer.

(B) Small commercial. A price to beat rate shall be calculated for each rate and service rider under which a small commercial customer was taking service on January 1, 1999, except as approved by the commission pursuant to subparagraph (C) of this paragraph. A price to beat rate shall not be calculated for any new service or tariff option granted to an affiliated electric utility pursuant to PURA §39.054, or for any rate of tariff option not in effect on January 1, 1999.

(i) Beginning with the first full billing cycle of the price to beat period, small commercial customers served by the affiliated REP shall be placed on the price to beat rate derived from the rate under which they were taking service on December 31, 2001.

(ii) Beginning with the first full billing cycle of the price to beat period, small commercial customers served by the affiliated REP beginning in January of 2002, who were taking service under a rate for which a price to beat rate was not developed, shall be placed on a price to beat rate derived from an eligible rate that was or would have been available to the customer on January 1, 1999.

(iii) New small commercial customers after December 31, 2001, may choose any price to beat rate for which they meet the eligibility requirements as detailed in the applicable price to beat tariff.

(iv) Small commercial customers who return to the affiliated REP after being served by a non-affiliated REP may choose any price to beat rate for which they meet the eligibility requirements as detailed in the price to beat tariff(s).

(v) Notwithstanding clauses (i) – (iv) of this subparagraph, small commercial customers may request service under any price to beat tariff for which they are eligible. Selection of the most advantageous rate shall be the sole responsibility of the small commercial customer.

(C) An electric utility, on behalf of its future affiliated REP, shall file within 60 days of the effective date of this section, price to beat tariffs and supporting workpapers for the price to beat rates developed in accordance with subparagraphs (A) and (B) of this paragraph. At the time of this filing, the affiliated REP may request that a price to beat rate not be developed from a particular rate of service rider along with justification for the request. The electric utility shall provide notice to all customers currently taking service under such rates or service riders of the utility's request.

(2) **Base rate component of price to beat.** For the eligible rates identified in paragraph (1) of this subsection, the affiliated REP shall reduce each base rate component including any purchased power cost recovery factor (PCRF), in effect for the affiliated electric utility on January 1, 1999, by 6.0% in order to determine the base rate component of the price to beat, with the following exceptions:

(A) If base rates for the affiliated electric utility were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, then the price to beat shall be the rate in effect as a result of a settlement approved by the commission after January 1, 1999.

(B) For affiliated REPs operating in a region defined by PURA §39.401, the commission may reduce rates by less than 6.0% if the commission determines a lesser reduction is necessary and consistent with the capital requirements needed to develop the infrastructure necessary to facilitate competition among electric generators.

(C) Except as provided in subparagraphs (A) and (B) of this paragraph, for any affiliated electric utility that has stipulated to rate reductions in a proceeding for which a final order had not been issued by January 1, 1999, such rate reductions shall be deducted from the base rates in effect on January 1, 1999, in addition to the 6.0% reduction. Such rate credits shall also be applied to the rates of the transmission and distribution utility.

(3) **Fuel factor component of price to beat.**

(A) Each affiliated electric utility shall file an application to establish one or more fuel factors, to be effective on January 1, 2002, according to the following schedule:

(i) April 1, 2001 - Reliant Houston Lighting & Power;

(ii) May 1, 2001 - TXU Electric Company;

(iii) June 1, 2001 - Texas-New Mexico Power Company and Central Power & Light Company;

(iv) July 1, 2001 - Entergy Gulf States, Inc. and West Texas Utilities;

(v) August 1, 2001 - Southwestern Electric Power Company and Southwestern Public Service Company.

(B) The rate year for the filing shall be calendar year 2002. The affiliated electric utility shall follow the requirements of §25.237(a)(1), (b), (c) and (e) of this title (relating to Fuel Factors) and the Fuel Factor Filing Package of November 23, 1993, for the filing of its fuel factor(s). To the extent that the commission has issued an order for a utility that includes provisions relating to the price to beat fuel factor, the price to beat fuel factor shall be set consistent with such an order.

(C) Subject to the limitations in clause (i) and (ii) of this subparagraph, affiliated electric utilities may utilize seasonal fuel factors to reflect the expected differences in the cost of the market price of electricity throughout the year.

(i) Affiliated electric utilities with seasonal fuel factors in effect on or before March 1, 2001, may request seasonal fuel factors for their residential and small commercial price to beat customers provided the level of seasonality is identical to that reflected in its commission-approved fuel factors on March 1, 2001.

(ii) Affiliated electric utilities without seasonal fuel factors in effect on or before March 1, 2001, may request seasonal fuel factors to be applicable to small commercial price to beat customers only. Any request for seasonal fuel factors under this clause must demonstrate that the average small commercial customer will receive, on an annual basis, a 6.0% reduction from the average bundled rate in effect on January 1, 1999, adjusted for the final fuel factor determined under subparagraph (D) of this paragraph; provided, however, that a utility subject to the exception in paragraph (2)(A) of this subsection must demonstrate that the average small commercial customer will receive, on an annual basis, the average bundled rate in effect as the result of a settlement approved by the commission after January 1, 1999, adjusted for the final fuel factor determined under subparagraph (D) of this paragraph.

(D) Each affiliated electric utility shall file additional information on October 1, 2001, to reflect changes in the price of natural gas for the rate year of 2002. The affiliated electric utility shall also file information necessary to determine the initial headroom that exists under the price to beat as a result of the setting of the initial price to beat fuel factor pursuant to this subparagraph. The adjustment shall be calculated using the following methodology:

(i) For the ten-day period ending on September 15, 2001, an average price shall be calculated for each month of 2002 in the closing forward NYMEX Henry Hub natural gas prices, as reported in the Wall Street Journal.

(ii) All other inputs into the calculation of the fuel factors will be the same as those used to calculate the fuel factor in subparagraphs (B) and (C) of this paragraph.

(iii) Except for affiliated electric utilities whose base rates were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, the fuel factor(s) to be used at the beginning of the price to beat period shall be the fuel factor in effect on January 1, 1999, reduced by 6.0%, plus the difference between the fuel factor(s) established pursuant to this subparagraph and the fuel factor in effect on January 1, 1999.

(iv) The fuel factor(s) for affiliate electric utilities whose base rates were reduced by more than 12% as the result of a final order issued by the commission after October 1, 1998, to be used at the beginning of the price to beat period shall be the fuel factor(s) established pursuant to this subparagraph.

(E) For a non-generating investor-owned utility with no fuel factor as of January 1, 1999, its PCRF in effect on January 1, 1999, shall be the equivalent to a fuel factor for purposes of calculating its price to beat rates and future fuel cost adjustments under subsection (g) of this section. Upon expiration of a purchased power contract of an affiliated REP unbundled from such a utility, the affiliated REP may request a change in its PCRF to account for any difference in purchased power costs.

(g) **Adjustments to the price to beat.**

(1) **Fuel factor adjustments.** An affiliated REP may request that the commission adjust the fuel factor(s) established under subsection (f)(3) of this section upward or downward not more than twice in a calendar year if the affiliated REP demonstrates that the existing fuel factor(s) do not adequately reflect significant changes in the market price of natural gas and purchased energy used to serve

retail customers. As part of a filing made pursuant to this paragraph, an affiliated REP may also request an adjustment to the seasonality imparted to the fuel factor in accordance with subsection (f)(3)(C) of this section. Alternatively, the commission may, as part of its approval of an adjustment to the fuel factor, impose a change in the seasonality imparted to the fuel factor. The methodology for calculating the adjustment to the fuel factor(s) shall be the following:

(A) For each day of the 20 trading-day period ending no later than two days before the filing of a fuel factor adjustment application, an average of the closing forward 12-month NYMEX Henry Hub natural gas prices, as reported by the *Wall Street Journal* (either in print or on-line), is calculated.

(B) The average forward price for each trading day calculated in subparagraph (A) of this paragraph will then be averaged to determine a 20 trading-day rolling price.

(C) The percentage difference between the averaged 20 trading-day rolling price calculated under subparagraphs (A) and (B) of this paragraph and the averaged price used to calculate the current fuel factor(s) is calculated. If the current fuel factor was calculated through an adjustment under subparagraph (E) of this paragraph, then the averaged 20 trading-day rolling price calculated concurrent with that adjustment shall be used. If the percentage difference is 5.0% or more, then the current fuel factor(s) may be adjusted, unless the filing is made after November 15 of a calendar year, in which event the percentage difference must be 10% or more.

(D) If the absolute value of the percentage difference calculated in subparagraph (C) of this paragraph meets or exceeds 5.0% (or 10% if applicable), then the current fuel factors are deemed to be unreflective of significant changes in the market price of natural gas and purchased energy. To adjust the current fuel factor(s), the percentage difference calculated in subparagraph (C), either positive or negative, is added to one and then multiplied by the current factor(s). The results are the adjusted fuel factor(s) that will be implemented according to the procedural schedule in clause (i) and (ii) of this subparagraph:

(i) if no hearing is requested within 15 days after the petition has been filed, a final order shall be issued within 20 days, or as soon as practicable thereafter, after the petition is filed;

(ii) if a hearing is requested within 15 days after the petition is filed, a final order shall be issued within 45 days, or as soon as practicable thereafter, after the petition is filed. The 45 day timeline for issuance of an order may be extended upon mutual agreement of the parties. Such agreement may provide for interim rate relief.

(E) In addition to the adjustment permitted under subparagraphs (A)-(D) of this paragraph, an affiliated REP may also request an adjustment to the fuel factor if the headroom under the price to beat decreases as a result of significant changes in the price of purchased energy. In making a request under this subparagraph:

(i) an affiliated REP shall demonstrate that:

(I) the representative power price has changed such that the headroom under the price to beat has decreased; and

(II) the adjustment to the fuel factor is necessary to restore the amount of headroom that existed at the time that the initial price to beat fuel factor was set by the commission using then current forecasts of the representative power price.

(III) an affiliated REP making an adjustment under this subparagraph shall also file the gas price calculation in subparagraphs (A) and (B) of this paragraph for purposes of subsequent adjustments to the fuel factor based on changes in natural gas prices.

(ii) the commission will issue a final order on an application filed under this subparagraph within 60 days, or as soon as practicable thereafter, after the application is filed. The 60 day timeline for issuance of an order may be extended upon mutual agreement of the parties. Such agreement may provide for interim rate relief.

(F) The commission shall, upon a showing made by an interested party, that a sufficiently liquid electricity commodity trading hub (or hubs) or index has developed for the affiliated REP's relevant geographic or power region, allow an affiliated REP to transition to the use of electricity commodity futures prices at that hub or index to adjust the fuel factor to adequately reflect significant changes in the price of purchased energy. After the commission has made a finding that a sufficiently liquid electricity commodity trading hub or index has developed, the affiliated REP shall be required to perform an additional adjustment under subparagraphs (A) through (D) or (E) of this paragraph before utilization of the futures prices at that trading hub or index to change the fuel factor so that a benchmark electricity price can be established. Subsequent changes to the fuel factor shall be based on the percentage change in the electricity commodity index using the same methodology for the natural gas price adjustment under subparagraphs (A) - (D) of this paragraph.

(2) **Adjustment for financial integrity.** Upon a finding that an affiliated REP will be unable to maintain its financial integrity if it complies with subsection (f) of this section, the commission shall set the affiliated REP's price to beat at the minimum level that will allow the affiliated REP to maintain its financial integrity. However, in no event shall the price to beat exceed the level of rates, on a bundled basis, charged by the affiliated electric utility on September 1, 1999, adjusted for fuel.

(3) **True-up adjustment.** The commission shall adjust the price to beat following the true-up proceedings under PURA §39.262. The commission shall consider the following adjustments to the price to beat on a schedule consistent with the

processing of the TDU rate adjustment application pursuant to §25.263(n) of this title (relating to True-up Proceeding):

(A) **Fuel factor adjustment.** A 20 trading-day rolling price shall be calculated in accordance with paragraph (1)(A)-(D) of this subsection. If the 20 trading-day rolling price is less than the price used to calculate the then-current fuel factor (i.e. the percentage difference is negative), then the price to beat fuel factor shall be adjusted downward by the percentage difference in the prices. An adjustment required to be made in accordance with this subparagraph shall not be considered a request by an affiliated REP under paragraph (1) of this subsection.

(B) **Base rate adjustment.** Using the typical residential and small commercial usage calculations described in subsection (c)(3) of this section, the base rate components of the price to beat shall be adjusted, either upward or downward, such that the difference between the average price to beat base rate and the average non-bypassable charges that exist following the proceeding pursuant to §25.263(n) of this title is the same as existed on January 1, 2002. Each component of the base rates for each residential price to beat base rate tariff shall be adjusted in the same proportion in complying with this section. Each component of the base rates for each small commercial price to beat base rate tariff shall be adjusted in the same proportion in complying with this section

(C) **Filing by affiliated REP.** An affiliated REP shall make filings necessary to implement subparagraphs (A) and (B) of this paragraph on a schedule to be determined by the commission.

(h) **Non-price to beat offers.**

(1) **Offers to residential customers.** An affiliated REP may not offer any rates other than the price to beat rates to residential customers within the affiliated electric utility's service area until the earlier of 36 months after the date customer choice is introduced, or when the commission determines that an affiliated REP has met or exceeded the threshold target for residential customers described in subsection (i) of this section, except as provided by §25.454 of this title (relating to Rate Reduction Program).

(2) **Offers to small commercial customers.** An affiliated REP may not offer rates other than the price to beat rates to small commercial customers until the earlier of 36 months after the date customer choice is introduced, or when the commission determines that an affiliated REP has met or exceeded the threshold target for small commercial customers described in subsection (i) of this section.

(3) **Offers to aggregated small commercial load.** Notwithstanding paragraph (2) of this subsection, an affiliated REP may charge rates different from the price to beat for service to aggregated loads having an aggregated peak demand in excess of 1,000 kW provided that all affected customers are commonly owned or are franchisees of the same franchisor.

(A) If aggregated customers whose loads are served by an affiliated REP in accordance with this subsection disaggregate, those individual customers may resume service under the applicable price to beat rate(s), provided that those customers meet the eligibility requirements of subsection (e) of this section.

(B) Any usage removed from the threshold calculation in subsection (i)(1)(B) of this section due to aggregation shall be added back into the threshold calculation upon disaggregation of the aggregated load.

(i) **Threshold targets.**

(1) **Calculation of threshold targets.**

(A) Residential target. The residential threshold target shall be equal to 40% of the total number of kilowatt-hours (kWh) consumed by residential customers served by the affiliated electric utility during the calendar year 2000.

(B) Small commercial target. The small commercial threshold target shall be equal to 40% of the following difference: the total number of kWh consumed by small commercial customers served by the affiliated electric utility during the calendar year 2000 minus the aggregated load served by the affiliated REP that complies with the requirements of subsection (h)(3) of this section. The kWh associated with a customer who becomes ineligible for the price to beat because the customer's peak demand exceeds 1,000 kW shall also be removed from the threshold target.

(2) **Meeting of threshold targets.** Upon a showing by the affiliated transmission and distribution utility that the electric power consumption of the relevant customer group served by nonaffiliated REPs meets or exceeds the targets determined by the calculation in paragraph (1) of this subsection, the affiliated REP may offer rates other than the price to beat.

(A) Calculation of residential consumption. The amount of electric power of residential customers served by nonaffiliated REPs shall equal the number of residential customers served by nonaffiliated REPs, except customers that the affiliated REP has dropped to the POLR, times the average annual consumption of residential customers served by the affiliated utility during the calendar year 2000.

(i) The number of customers served by nonaffiliated REPs shall be determined by summing the number of customers in the transmission and distribution utility's certificated service area with a designated REP other than the affiliated REP in the registration database maintained by the registration agent. Customers dropped to the POLR by the affiliated REP shall not count as load served by a nonaffiliated REP.

(ii) The average annual consumption shall be calculated by dividing the total kWh consumed by residential customers during the calendar year 2000 by the average number of residential customers during the calendar year 2000. The average number of residential customers during the calendar year 2000 shall be calculated by dividing the sum of the total number of such customers for each month of the year 2000 by 12.

(B) Calculation of small commercial consumption. The amount of electric power consumed by small commercial customers served by nonaffiliated REPs shall be determined using the following criteria, except that customers served by the POLR shall not count as load served by a nonaffiliated REP:

(i) The amount of electric power of small commercial customers with peak demand less than 20 kW consumed by nonaffiliated REPs shall be equal to the number of small commercial customers with peak demand less than 20 kW served by nonaffiliated REPs times the average annual consumption of small commercial customers with peak demand less than 20 kW served by the affiliated electric utility during the calendar year 2000.

(I) The number of customers served by nonaffiliated REPs shall be determined by summing the number of small commercial customers with peak demands less than 20 kW served in the transmission and distribution utility's certificated service area with a designated REP other than the affiliated REP in the registration database maintained by the registration agent.

(II) The average annual consumption shall be calculated by dividing the total kWh consumed by small commercial customers with peak demand of less than 20 kW during the calendar year 2000 by the average number of small commercial customers with peak demand of less than 20 kW during the calendar year 2000. The average number of small commercial customers with peak demand of less than 20 kW shall be calculated by dividing the total number of such customers for each month of 2000 by 12.

(ii) The amount of electric power consumed by small commercial customers with peak demand in excess of 20 kW shall be the actual usage of those customers during the calendar year 2000.

(I) If less than 12 months of consumption history exists for such a customer during the calendar year 2000, the available calendar year 2000 usage history shall be supplemented with the most recent prior history of service at that customer's location for the unavailable months.

(II) For customers with service to a new location, the annual consumption shall be deemed to be equal to the estimated maximum annual demand used by the affiliated transmission and distribution utility in sizing the facilities installed to serve that customer multiplied by the product of 8,760 hours and the average annual load factor for small commercial customers with peak demand greater than 20 kW for the year 2000.

(j) **Prohibition on incentives to switch.** An affiliated REP may not provide an incentive to switch to a nonaffiliated REP, promote any nonaffiliated REP, or exchange customers with any nonaffiliated REP in order to meet the requirements of subsection (f) of this section. Non-affiliated REPs may not provide an incentive to return to the price to beat.

(k) **Disclosure of price to beat rate.** An affiliated retail electric provider shall disclose to customers, the price to beat in accordance with §25.471 (relating to General Provisions of Customer Protection Rules). In addition, if an affiliated REP offers a rate greater than the price to beat, the price to beat rate must be disclosed along with a statement that the customer is eligible for the price to beat. This disclosure must appear on all written authorizations, Internet authorizations, the electricity facts label and Terms of Service document. It must also be disclosed during telephone solicitations before the customer authorizes service.

(l) **Filing requirements.**

(1) On determining that its affiliated retail electric provider has met the requirements of subsection (i) of this section, an electric utility or transmission and distribution utility shall make a filing with the commission attesting under oath to the fact that those requirements have been met and that the restrictions of subsection (h) of this section as well as the true-up in PURA §39.262(e) are no longer applicable.

(2) An electric utility or transmission and distribution utility shall file a progress report with the commission after its affiliated REP has met the requirements of subsection (i) of this section using a 35% threshold target in lieu of a 40% threshold. Such progress reports(s) shall be filed no later than 30 days after the 35% threshold has been met and shall contain the same information required in this subsection.

(3) No later than December 31, 2001, each transmission and distribution utility shall determine the power consumption threshold targets under subsection (i) of this section for residential and small commercial customers within its certificated service area and shall file this information with the commission and shall also make this information publicly available through its Internet website. Each transmission and distribution utility, together with its affiliated REP, shall update the small commercial power consumption threshold as needed to reflect additional small commercial load that has met the requirements of subsection (h)(3) of this section and therefore is appropriately removed from the calculation of the threshold target. Concurrent with this update, the transmission and distribution utility, together with its affiliated REP, shall provide, for each group

of aggregated customers that have been removed from the calculation of the threshold target, the customers' names, electric service identifiers, size of the customers' loads (individually and in the aggregate), and how the customers meet the requirements of subsection (h)(3). Such information may be filed under confidential seal. All certificated REPs shall be deemed to have standing to review such filings.

(4) Any application filed pursuant to this subsection shall contain the following information:

(A) a detailed explanation of how the relevant customer group has met or exceeded the threshold consumption targets in subsection (i) of this section;

(B) calculation of the power consumption threshold target under subsection (i) of this section for the relevant customer group and the date such target was met;

(C) verification of the meeting of the threshold target in the following manner:

(i) for the residential customer class, independent verification from the registration agent verifying the number of customers in the residential customer class within the transmission and distribution utility's certificated service area that are committed to be served by non-affiliated REPs.

(ii) for the small commercial class, an affidavit detailing the number of customers in the small commercial class with peak demand below

20 kW within the transmission and distribution utility's certificated service area committed to be served by non-affiliated REPs and the customers with peak demand in excess of 20 kW with their actual usage calculated in accordance with subsection (i)(2)(B)(ii) within the transmission and distribution utility's certificated service area that are committed to be served by non-affiliated REPs.

(iii) For purposes of this subsection, a residential and small commercial customer has committed to be served by a nonaffiliated retail electric provider if the registration agent has received a switch request for that customer and any mandated cancellation period pursuant to applicable commission rule has expired.

(5) The commission staff shall review all applications filed under this subsection and shall make a recommendation to the commission within ten days after the application is filed to approve or reject the application. If a filing has insufficient information from which the commission can make a determination, the commission may reject the filing without prejudice for refiling the application. The commission shall issue an order approving or rejecting the application within 30 days after the application is filed. An electric utility or transmission and distribution utility filing an application under this subsection shall not charge rates different from the price to beat until the earlier of 36 months after the date customer choice is introduced or the date such application has been approved by the commission.

This agency hereby certifies that the rule, as adopted, has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.41 relating to Price to Beat is hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 2nd DAY OF APRIL 2003.

PUBLIC UTILITY COMMISSION OF TEXAS

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Rebecca Klein, Chairman

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Brett A. Perlman, Commissioner

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Julie Caruthers Parsley, Commissioner