The Public Utility Commission of Texas (commission) adopts new §25.381, relating to Capacity Auctions, with changes to the text as published in the September 15, 2000, *Texas Register* (25 TexReg 9139). This rule implements the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §39.153 (Vernon 1998, Supplement 2000), as it relates to the establishment of procedures by which affected affiliated power generation companies (PGCs) will auction entitlements to 15% of their Texas jurisdictional installed generation capacity beginning 60 days before the implementation of customer choice. PURA Chapter 39, Restructuring of the Electric Industry, became effective September 1, 1999, as part of Senate Bill 7, 76th Legislative Session, to effectuate a competitive retail electric market that allows each retail customer to choose its provider of electricity and encourages full and fair competition among all providers of electricity. This new section is adopted under Project Number 21405.

The commission received written comments and/or reply comments on the proposed new section from American Electric Power Company (AEP), Competitive Power Advocates (CPA), Reliant Energy, Inc. (Reliant), TXU Electric Company (TXU), Office of Public Utility Counsel (OPC), Consumers Union (Consumers), AES NewEnergy, Inc. (NewEnergy), Entergy Gulf States, Inc. (EGSI), Southwestern Public Service Company (SPS), PG&E National Energy Group (PG&E), Texas-New Mexico Power Company (TNMP), Steering Committee of Cities Served By TXU and the Steering Committee of Cities Served By CPL (Cities), El Paso Merchant Energy (EPME), Oxy USA, Inc. (Oxy), City of Austin doing business as Austin Energy (Austin Energy), El Paso Electric Company (EPE), Texas Industrial Energy Consumers (TIEC), and Alliance for Retail Markets (ARM).

A public hearing was held at the commission's offices on October 20, 2000. Representatives from TXU, TNMP, AEP, and OPC attended the hearing and provided comments. To the extent these oral comments differ from the submitted written comments, such comments are summarized herein.

Comments on specific questions posed in the rule:

The commission requested specific comments with respect to ten questions related to the development of the final rule. The parties' responses to those questions are summarized below. Several parties also provided redlined versions of the proposed rule suggesting rule language that should be used to incorporate their recommendations and comments. To the extent that language is duplicative of the comments received, such language is not repeated here.

Question Number 1: Does the rule reflect an appropriate level of firmness for the products?

OPC stated that the products will have relatively little value in the market because of their interruptibility and are inferior to capacity purchased in the market. Cities stated that requiring the products to be firm will increase the number of interested market participants and encourage more realistic prices. NewEnergy suggested that the products should be financially firm with liquidated damages. PG&E generally stated that the rule should provide for greater firmness than currently contemplated due to the slice of system approach embodied in the rule. PG&E argued that in order for retail electric providers (REPs) to provide reliable, consistent service, REPs and wholesalers must be able to purchase firm capacity in the marketplace.

EGSI, TXU, and Reliant noted that the proposed rule creates a new breed of firm product, not available in the market today and recommended that the commission not create a product that is more firm than the overall system. Reliant also noted that the sale of a product more firm than the system will lead to an inaccurate result in the excess cost over market (ECOM) true-up. Reliant recommended that all outages be shared pro-rata among the affiliated PGCs and entitlement holders. Reliant also proposed that a separate "firmness" hedge product could be sold at the time of auction, thus providing firmness to those entities that want it at a market price. AEP suggested that dispatch rights could be set at 85% of the entitlement as a solution to the firmness problem. PG&E responded that the utilities neglected to recognize that part of their system is firm, as the utility retains flexibility in dispatching their units to meet entitlements and utilities today use their system to provide firm service to their current customers. PG&E also noted that the affiliated PGCs will be able to offer firmer products that those that are available through the capacity auctions, if the utility's proposal is adopted.

Austin Energy recommended that the terms planned outage and forced outage be defined in a way to limit subjective interpretation by PGCs. Austin Energy also suggested that a credit against the capacity charge be applied whenever the cumulative duration of outages exceeds 10% of the entitlement period, in order to prevent gaming by PGCs.

TXU proposed that the entitlements be 100% financially firm, but that utilities auction fewer entitlements in the off-peak months to reflect the reduced availability due to maintenance. TXU suggested that this would eliminate the need for notice of outages and provide a firm product to the market. In reply comments, Austin Energy also stated that there should be no planned outages for entitlements, but the amount of capacity offered in a month should take into account the planned outage schedule. Austin Energy suggested that this would simplify the auctions and minimize the opportunity for market manipulation by PGCs tinkering with outage schedules. Cities and OPC also agreed with TXU in reply comments and suggested a formula that could be used to determine the amount of capacity to be sold within each product type and time period. Cities also suggested that such an approach would eliminate potential disputes about why and when actual outages occur. PG&E concurred that TXU's proposal provided a reasonable compromise, provided that the maximum outage rate for non-peak months is limited to 10%.

TNMP suggested that the level of firmness seemed appropriate.

Planned outages:

EGSI, TXU and AEP stated that the requirements for affiliated PGCs to provide planned outage notification requires the release of competitively sensitive information to the market that would put certain entities at a disadvantage in the market. EGSI further noted that outage scheduling is a dynamic process, and it may be impossible to predict such outages with accuracy on a six-month basis. EGSI proposed a three-month notice schedule provided in aggregate for each group of units. AEP suggested that the commission should require all PGCs to make maintenance schedules public to eliminate any competitive advantage. TXU suggested that the products could be made "financially firm" to resolve this concern.

PG&E stated that the current rule fails to provide adequate certainty, and recommended that no planned maintenance should be scheduled for the peak months of June through September and December through February, and that a schedule be provided in the auction notice for planned outages in the other months. PG&E recommended that the commission require that planned maintenance be scheduled in off-peak periods to minimize potential price spikes and that the products be financially firm in the on-peak months. PG&E also stated that a purchaser should be held harmless from a change in planned maintenance schedules because purchasers will be unable to plan for such unilateral alterations in the schedules, and that the utilities are in the best position to manage the risk associated with any outages. TXU responded that provision of outage schedules would require affiliated PGCs to disclose competitively sensitive information. EGSI also noted that it is unrealistic and imprudent to require that the entitlement dictate the planned outage schedule for the entire fleet. PG&E noted in reply comments that it is common in market transactions today for the supplier to notify buyers of planned maintenance schedules.

Forced outages:

EGSI and TXU recommended that forced outages be shared proportionately by the affiliated PGC and entitlement holders to reflect the reality of outages. PG&E recommended firm products with at least 98% guaranteed availability with liquidated damages for forced outages in excess of the 2.0%, as this arrangement is common in tolling agreements. TXU agreed that such forced outages should be limited to no more than 2.0% of the hours. Reliant responded that PG&E's proposal failed to recognize the realities of operating a generating system, which do not usually operate at a 98% availability rate.

The commission generally finds that the capacity auction products will have the most value to the market as firm products, however, it recognizes that PURA contemplates availability subject to outages. The commission finds that TXU's proposal provides the best solution to the firmness issue. Requiring 100% financial firmness will provide potential buyers of the entitlements certainty in the products they are buying, while reducing the amount of entitlements to be sold in off-peak months will recognize the reduced availability of units due to maintenance requirements. As such, the commission finds that it is appropriate to require affiliated PGCs to auction entitlements at 100% of the required capacity in the peak months, and authorizes utilities to auction an amount of entitlements in off-peak months that recognizes the reduced availability of capacity due to planned outages. Language has been added to subsection (e)(1) to incorporate this concept. Subsection (f)(3)(A)(v) has been added to clarify that the reduction in available entitlements in off-peak months will be in the entitlements sold as discrete months. The commission also finds that it is appropriate to retain the existing language with respect to forced outages, but further limits such outages to not more than 2.0% of the hours of the entitlement, consistent with PG&E's recommendation. Language has been added to subsection (e)(2) to incorporate this limitation. Utilities will therefore be required to file historical outage information with the commission, but will not be required to provide prospective outage information to the marketplace. This requirement has been added to subsection (e)(3).

Question Number 2: The heat rates specified in the "fuel price" sections of the gas product descriptions are intended to be standardized across the state in order for the products to be more tradable in a secondary market. Are the heat rates set at an appropriate level to be used as a statewide standard?

OPC stated that to the extent heat rates are based on historical operation, the heat rates will be too high. As a result, revenues will be based on inefficient heat rates that do not correspond to the newer, more efficient heat rate units that will displace older generation, resulting in windfall profits to the utilities. Cities did not object to standardized heat rates, but expressed concern that the proposed rule assumes heat rates derived from Reliant with little support. Cities also stated that the energy sold under the peaking entitlements will more often than not be produced when gas-fired steam capacity is at the margin. TXU responded that no rational market participant would dispatch an entitlement when the market price for energy is less than the cost of energy from the entitlement. NewEnergy recommended products that are not specified by heat rate, and instead be designed to be similar to products that exist in the wholesale market.

PG&E stated that the heat rates in the proposed rule are consistent with those seen in the marketplace and stated that no adjustments were needed. However, PG&E noted that the "slice of system" approach utilized in the rule means that a utility could in fact use lower heat rate units to provide a particular product, raising the net revenues to the utility. PG&E and Cities suggested that it was therefore appropriate to reconcile fuel revenues with actual fuel costs, as proposed in the rule. TNMP agreed in reply comments. AEP and Reliant argued that this went far beyond the command of PURA, which already has detailed methods for determining market value and such a prudence review is beyond the scope of this rule and not supported by the statute. Reliant argued that the products have been designed such that the fuel cost paid by the entitlement holder mirrors the fuel cost incurred by the asset holder and a reconciliation was therefore unnecessary.

PG&E and Reliant supported standardized products across the state in order to enhance liquidity and tradability. TXU responded by noting that regardless of the heat rates used for the entitlements, entitlement holders may sell the energy available from an entitlement without selling the entitlement itself.

EGSI, TXU, EPE, OPC and AEP disagreed that the heat rates should be standardized, as it may create arbitrary loses and gains for PGCs. EGSI and AEP both suggested the adoption of company specific heat rates, or the establishment of average heat rates by congestion zone or power pool. Cities agreed in reply comments with AEP that the heat rates should be based on the actual weighted average heat rate for each capacity type offered at auction. Cities also stated that the energy charge for baseload energy should be set at the 1999 statewide weighted average fuel cost for coal, lignite and nuclear generation. Cities stated that a reconciliation of actual fuel cost and actual revenues would address EGSI, TXU, and AEP's concerns about inequities among utilities. TNMP stated that the heat rates should correspond as closely as possible to the actual rate the individual investor owned utilities (IOUs) maintain on their systems as such rates will be used by the market in the valuation of the products. TXU suggested that the heat rates could be provided in a filing with commission staff in advance of the first auction. CPA agreed with TXU in its reply comments. Reliant noted in its reply comments that use of a heat rate curve can address some of the concerns of the various parties.

The commission recognizes that the use of a standard heat rate for the gas products will naturally result in heat rates that are not representative of all (or any) utilities. However, the commission agrees with PG&E that the competitive market is best served through the establishment of standard products and agrees with PG&E that the heat rates specified in the rule are fairly representative of the marketplace. No change to the rule has been made.

Question #3: Are fuel service costs and start-up fees appropriate? Should these costs be standardized across the state and if so, are the appropriate values included in the proposed rule?

Cities argued that no evidence exists to justify such adders, and adoption of such adders is inconsistent with the commission's decision relating to its calculation of the market price of electricity approved in Docket Number 22344, *Generic Issues Associated with Applications for*

Approval of Unbundled Cost of Service Rates Pursuant to PURA §39.201 and Public Utility Commission Substantive Rule §25.344. NewEnergy, CPA, and TNMP stated that such fees are not necessary in the slice of system approach adopted by the rule. EGSI agreed and noted that in its case, it did not expect the dispatch of entitlements to affect the dispatch of its units. PG&E agreed and suggested that because the proposed heat rates were at the high end of the reasonable range for such products, fuel service costs are subsumed within the heat rate and capacity payment, and that inclusion of such fees within the heat rates will simplify the auctions. Cities and TNMP agreed in reply comments with PG&E that these costs are best accounted for in the heat rates. Reliant disagreed in reply comments stating that it neglected the fact that only a portion of start up costs are assigned to the entitlements to reflect the entitlement only being a portion of the unit.

TXU argued for the use of company specific fees and start-up costs and suggested language to incorporate this change. TXU stated that start-up fees and fuel service charges represent real costs to PGCs and will be incurred in the provision of the entitlements. AEP agreed in reply comments. CPA, in reply comments, suggested that each utility be required to file cost information for fuel service costs and start-up fees prior to the first auction.

EGSI, AEP, and EPE also suggested the use of different hubs for natural gas prices. TXU suggested changes to the rule in reply comments that would incorporate this concern.

The commission agrees with the parties that suggest that start-up fees and fuel service costs are appropriately subsumed within the heat rates, and doing so will simplify the auctions. Appropriate changes to the rule have been made in subsection (e)(1)(A) through (D). However, the commission does recognize that these costs may be real costs incurred in the provision of entitlements. To the extent these costs are no longer recovered through separate charges, the commission believes it is appropriate for utilities to include these costs in the establishment of their opening bid prices in order to ensure their recovery. This clarification has been made to subsection (f)(7).

Question Number 4: Are the credit requirements detailed in subsection (e)(5)(D) consistent with typical credit requirements in wholesale markets and with other credit requirements previously adopted by either the commission or ERCOT?

NewEnergy stated that credit requirements are generally two months of maximum charges, and to the extent the entitlements require higher deposits than other products, market participants may seek other alternatives in the market or incorporate those added costs into their bids, resulting in a distorted market price. EGSI supported the adoption of standard credit requirements. PG&E and Reliant supported the proposed credit standards, but PG&E noted that such terms are usually reciprocal, as reciprocity will provide confidence in a seller's ability to perform and provide a level playing field. TXU replied that PG&E's proposal ignores the fact that affiliated PGCs are required to auction entitlements under Senate Bill 7 and cannot choose not to do so.

TNMP suggested that the requirements be relaxed to only include continuing payments. AEP suggested changes to make the requirement consistent with those recommended by AEP to other commissions. TXU agreed with AEP and further suggested changes to make clear the payment obligations of the entitlement holder and that financial instruments be in a form and from an issuer reasonably acceptable to the seller, as such language is common in wholesale market transactions. TXU also recommended removal of subsection (e)(5)(D)(i)(V), a loan issued by an affiliate, as an option, as this option does not give any security to the affiliated PGC unless the proceeds of the load are deposited with the affiliated PGC or an escrow agent.

The commission finds that the credit standards included in the rule are consistent with those previously adopted by the commission, but agrees with TXU that, for purposes of this rule, the option of a loan issued by an affiliate does not provide sufficient security to the affiliated PGC unless deposited with the PGC or an escrow agent. The commission therefore deletes the subclause, but notes that the requirements of subsection (e)(5)(D)(i)(II) could be met through the depositing of a loan from an affiliate. The commission declines to require reciprocity in the credit standards at this point in time.

Question Number 5: Given that the entitlement products are system capacity, should there be more flexibility in scheduling the baseload, gas intermediate, and gas cyclic products?

Several parties submitted extensive comments on the use of the products in ancillary services market in response to this question. Those comments are discussed in further detail after the discussion of Question Number 10.

NewEnergy supported the system capacity approach because such an approach can provide significant flexibility. Cities argued for the removal of scheduling restrictions as such restrictions would make the products inferior to capacity retained by the utilities because such capacity is not subject to similar restrictions. Specifically, Cities argued for day-ahead notice for baseload and intermediate capacity and one-hour notice for peaking capacity, with multiple daily start-ups. PG&E and CPA stated that the scheduling provisions should be representative of system capacity and consistent with ERCOT protocols, and while the start-up times appeared reasonable, the ramp-up limitations and minimum take provisions are inconsistent with that premise and are unnecessary. CPA also stated that entitlements should be able to be used for the full range of capacity, energy, and ancillary service needs in the market and recommended intra-day energy deployment flexibility to allow entitlement holders to use Responsibility Transfer Mechanisms in the ERCOT protocols to designate entitlements for purposes of providing ancillary services resources. TNMP suggested more flexibility, but limited to the normal use of the relevant type of units in order to make the products more usable in ancillary services markets. TNMP proposed a methodology that assigns the slice of system a corresponding slice of ancillary services capability. Reliant responded that this ignores the characteristics of the underlying generation assets.

EGSI and TXU supported the scheduling parameters. Reliant proposed reducing the minimum take for the gas-intermediate product from 50% to 30% in order to make the product more flexible. TXU agreed that such a reduction was appropriate in reply comments. OPC replied that this moved in the right direction, but still was not flexible enough. In reply comments, Reliant further proposed additional flexibility in the baseload and gas intermediate products to improve flexibility, specifically, allowing between 80% to 100% take from the baseload product, and allowing starts and stops of the gas intermediate products.

The commission agrees that the products should be as flexible as possible while still recognizing the nature of the underlying generation assets. As such the commission adopts Reliant's proposed changes for the baseload product and makes corresponding changes to subsection (e)(5)(C)(i). The commission also adopts Reliant's proposed reduction in the minimum take requirement for the gas-intermediate product in subsections (e)(1)(B) and (e)(5)(C)(ii).

Question Number 6: Will the bid procedures, evaluation methodology, and determination and application of the market clearing price provide an appropriate valuation for the products? What procedures best balance the commission's goals of determining an appropriate market price, providing market liquidity, and facilitating price discovery and transparency?

OPC and Consumers stated that the use of a lowest winning bid as a market clearing price will result in the products being undervalued, and gives market participants an incentive to game the auction in an attempt to set the lowest possible market clearing price. OPC also suggested that the true-up provisions of PURA may also create an incentive for the sellers of the capacity to collude with buyers in an attempt to lower the prices received in the auctions. OPC and TXU suggested that multiple round bidding might be more appropriate. NewEnergy stated that the products will require refinement in the secondary market before they can be used and that will likely lead to depressed values in the auctions.

AEP and TXU supported a "pay what you bid" methodology to be applied to winning bids, as it will more closely track a bilateral market, will provide the marketplace with a range of prices instead of one, and will result in higher revenues. Cities supported the AEP proposal in reply comments, noting that it will likely increase revenues and recognizes the difference in value that individual bidders may place on a particular entitlement. Cities also suggested simultaneous bidding by capacity type, with sequential bidding across types. EPME also supported a single round, simultaneous auction as an equitable procedure that best protected the market from manipulation. PG&E responded that a "pay as you bid" approach leads bidders to bid low prices out of concern for over-paying for products, but noted a multiple round open bid process would minimize this. AEP noted that multiple round auctions are more costly to run, and provide more opportunities for disputes and disagreements.

Reliant, PG&E, and TNMP supported the existing bid methodology.

TXU provided discussion on a variety of auction options, including multiple round auctions and sequential auctions and recommended allowing entitlement sellers to have flexibility with how they design their auction procedures and allow the sellers to make changes to their bid procedures. These options were discussed further at the October 20, 2000 Public Hearing. TXU also suggested that the setting of an appropriate reservation price would aid in the provision of information to the market as to the proper value of an entitlement. OPC, TNMP, and CPA replied that a multiple round auction could be preferable to the procedure in the proposed rule, with OPC recommending inclusion of an activity rule requiring winning bidders to have bid in each round, a starting price at an appropriate reserve price, and recommended the establishment of bid increments after review of the auction characteristics. OPC re-iterated that each winner should pay the amount they bid. Reliant stated that if a multiple round auction is used, data from each round should be available only in aggregate for all bidders, and that the rounds should take place very quickly, which could only be done through an Internet bidding process. Reliant also suggested use of descending bid prices and noted that multiple round auctions increase the risk of collusion and noted that use of a "bid what you pay" structure may make the ECOM true-up difficult.

The commission agrees with the parties that recommended a multiple round auction and finds that the use of a multiple round bidding process will best value the capacity auction products. Specifically, the commission agrees with the parties that stated the multiple round auction approach discussed at the October 20, 2000 Public Hearing will provide better price discovery and transparency. Subsection (f)(6) has been revised to incorporate this bidding structure. Bidders in each round will be required to submit a quantity demanded for a particular entitlement at the price posted for the round. The commission agrees with OPC that the opening price in the first round should be tied to the opening (or reserve) price established by the affiliated PGC in accordance with the rule. The commission also agrees with OPC that an appropriate methodology needs to be developed to determine bid increments. As such, the notice for each pending auction will include the formula to be used to adjust the posted price between rounds. The development of a proper formula shall be discussed by the implementation group. In the absence of the development of a uniform methodology, each affiliated PGC shall provide its method in its notice. The commission agrees with Reliant that all winning bidders should pay the market-clearing price, which shall be the price in the next to last round. Winning bidders will therefore pay this price for the quantities they demanded in the last round plus a pro-rata share of any differential between the quantity available at auction and the quantity demanded in the last round, consistent with the discussion at the Public Hearing. The commission also agrees with Reliant that a multiple round auction may present gaming opportunities not present in other auction types. As such, bidders will not be permitted to bid greater quantities at higher prices, consistent with the presentation at the Public Hearing. The commission also agrees with Reliant that in order for the bidding to proceed in a timely fashion, an internet-based auction should be used. Such a requirement has been added in subsection (f)(6)(C).

Question Number 7: Is the true-up methodology in subsection (h) an appropriate methodology to incorporate the capacity auction revenues into the stranded cost true-up required by PURA §39.262? Is there an adjustment needed to those revenues in order to reflect products that are more firm than the overall system?

OPC argued that the determination of the true-up procedure should be done in the contested proceeding to occur in 2004, and not in the formula suggested by the rule and suggested that a utility with no CTC could get a windfall through the procedure. OPC also suggested that the heat rates may lead to inappropriate valuations of the products and suggested certain revisions that the commission should have made in its determination of the gas prices used in the ECOM model, which would have resulted in even lower estimates of ECOM in the current unbundled cost of service (UCOS) proceedings. OPC demanded that the true-up procedure be deleted from the rule, as it will lead to an overrecovery of stranded costs. ARM agreed in reply comments and recommended that the commission initiate a comprehensive rulemaking to address PURA §39.262. TXU responded that inclusion of language in this rule will reduce uncertainty about the true-up in 2004.

EGSI stated that the auctions should not produce products that are firmer than overall system. Cities argued that revenues from both demand and energy should be accounted for in the auction proceeds, including fuel service cost adders. Reliant argued that start-up fees should not be included in the revenues used in the true-up and on reply comments, argued that a fuel reconciliation was inappropriate and unnecessary.

Cities proposed that the reconciliation should include a month-by-month reconciliation of energy charge revenues and actual fuel costs incurred, and should be done separately for baseload and gas-fired capacity. Cities also stated that the rule should provide incentive for utilities to sell their assets in the manner that derives the most value for the assets, and that utilities should not be allowed to devalue their assets in an attempt to manipulate the final true-up calculation. PG&E agreed that to the extent start-up fees or other fees are permitted, they should be standardized and included in the true-up calculation.

TXU recommended that the fixed cost contribution from the ECOM model be divided by 12 in order to yield a monthly value for the true-up calculation. TXU also stated that it is inappropriate to reconcile non-market based gas costs as part of the true-up process as it is inconsistent with the Legislature's directive that fuel costs be finally reconciled as of December 31, 2001. TXU also suggested that it would be appropriate to revise the capacity auction revenues downward in order to reflect the increased firmness of the products over system firmness.

PG&E and CPA initially stated that the true-up methodology is reasonable and should reflect all receipts from the auctions. PG&E and CPA further stated that as firm products are readily available from independent power producers and are consistent with the products found in the marketplace, no adjustment was needed to reflect a greater degree of firmness than system firmness. However, on reply comments, PG&E and CPA recommended that the process be deferred to the broader true-up project as PG&E expressed concern that the process does not adequately reconcile all receipts from the capacity auctions.

SPS stated that the true-up should not apply to those utilities that are not seeking recovery of stranded costs and suggested that the rule as drafted requires such utilities to return the gains from the sales of generation assets to ratepayers, in direct contravention of the intent of the legislature. AEP agreed that the true-up should not apply to utilities with no stranded costs. In reply comments, Oxy and TIEC disagreed, stating that the SPS divestiture was not required as part of Senate Bill 7, but was a condition of the settlement approving the merger of its parent company, and that gains from the sales of those assets should be addressed in accordance with traditional regulatory principles, not the stranded cost provision of Senate Bill 7. Oxy did note that the true-up procedures in subsection (h) of the rule is the stranded cost true-up under PURA, which SPS will not be subject to if it does not have stranded costs. Oxy also noted potential problems for other utilities with positive ECOM if SPS's language is adopted. Oxy, TIEC, and OPC both stated that this issue should not be resolved in this rulemaking.

The commission agrees that the establishment of the true-up procedures may be premature at this time. The commission notes that there is disagreement with how this portion of the 2004 true-up should occur and believes that further exploration of this issue is warranted. The commission further notes that parties have not had the opportunity to comment on how the final products adopted by the commission should be incorporated into the true-up process. As such, the existing true-up language has been replaced with the language directly out of PURA describing the general process to be followed at the time of the true-up. Language has been included, however, noting that the true-up does not apply to utilities that did not request stranded cost recovery. The commission will consider the appropriate further detail of this process in a separate rulemaking, after parties have had an opportunity to consider the final capacity auction products and how they are appropriately accounted for in the stranded cost true-up to occur in 2004.

The commission agrees with Oxy, TIEC and OPC that the issue of what should be done with the gains from sales of SPS's plants is not an issue germane to this rulemaking. The commission finds that its order in Docket Number 21990, *Application of Southwestern Public Service Company Regarding Proposed Merger between New Century Energies, Inc. and Northern States Power Company*, appropriately addresses the reasons for and the nature of the divestiture of SPS's generation plants. The commission agrees that SPS, as a utility without stranded costs, is not subject to the portions of the 2004 true-up proceeding relating to stranded cost true-up, either prospectively for post 2004, or historically for the 2002-2004 period, for which capacity auction revenues will be used. Issues relating to what should be done with any gains from the sale of SPS's generation plants are properly considered in another proceeding, not in this rulemaking.

Question Number 8: The definition of "affiliated power generation company" in PURA §31.002(2) refers to a power generation company that is the successor in interest of an electric utility. If an electric utility places its generation in a non-affiliated company, is that company a "successor in interest" and therefore considered an "affiliated power generation company" for the purposes of remaining subject to the capacity auction requirement? Similarly, if generation assets are sold to a third party, does that third party become a "successor in interest" and therefore an "affiliated power generation company" and also become subject to the capacity auctions for those assets?

OPC suggested that companies are generally considered affiliates if one company owns over 5.0% of another company due to the common ownership. OPC suggested that as long as a PGC has any relationship that may lead it to favor an incumbent REP over other REPs, the PGC should be required to continue to auction entitlements, in order to insure that unaffiliated REPs have the ability to procure capacity. EGSI and SPS stated that a non-affiliated company or third party should not be considered a successor in interest or subject to the capacity auction requirements.

Reliant in reply comments stated that only if all of the assets were sold together or placed in a separate entity would the successor be considered an affiliated power generation company.

CPA, PG&E, TXU, and Oxy suggested that whether or not a subsequent owner is a "successor in interest" is a question of fact that may depend on the particulars of a transaction. PG&E did suggest that a successor in interest for the purposes of the capacity auction would be an entity that owns or controls a significant portion of the utility's generation assets, but again, that would involve a factual determination. AEP agreed that some purchasers should clearly not be considered successors in interest. Oxy also noted that the commission may, in SPS's transition to competition proceeding, require purchasers of SPS's capacity to participate in the auctions in order to aid in the development of a liquid market in SPS's power region.

The commission agrees with the parties that suggested that this issue is best resolved on a case by case basis. The definition of affiliated power generation company in this rule has not been changed.

Question Number 9: Should the gas price paid by the holder of an entitlement when that entitlement is struck be a known, fixed price at the time the entitlement is up for bid? Will having a known price make the products more usable and desirable to retail electric providers?

NewEnergy stated that a complete known price is crucial for REPs to use these products to serve retail load, and that the costs of the risk management tools that REPs will need to procure in the marketplace may inhibit REPs from participating in the auctions. NewEnergy proposed alternate products in the form of a baseload product, an on-peak product and an off-peak product, each of which would be a must-take product for varying durations and times, and a call option product, which would be a right but not an obligation to purchase up to the size of the entitlement each hour. Bids for each of the products would be a dollar per megawatt hour (MWh) bid, with a minimum take also bid for the call option product. TNMP agreed that price certainty was a desirable goal but noted it will be difficult to evaluate the proper price for such contracts. Austin Energy stated that the fuel price must be known at the time of the auction and not be subject to future changes.

EGSI, CPA, PG&E, AEP, TXU, Reliant and Cities generally stated that requiring a known gas price at the time of auction would effectively require the affiliated PGC to enter into hedging transactions for the purpose of offering a fixed price in the auctions. AEP further noted that the entitlements may be more valuable to entities who believe that they can hedge gas prices in a way superior to that of the selling PGC and stated that the commission should defer the existing futures market for the provision of gas hedging products. TXU also suggested that such a requirement would go beyond the scope of PURA and would effectively create an electricity option product.

The commission recognizes that hedging products exist in the market place today and agrees that market participants may better perform this function than the affiliated PGCs. The commission believes that although the products proposed by NewEnergy have the advantage of being simple, they are basically energy products, and have few attributes of capacity. The greater flexibility allowed by the capacity products outlined in the rule better facilitate the competitive market; the products desired by NewEnergy will likely be provided in the market, in part from the entitlement products mandated by the rule. No change to the rule is required.

Question Number 10: Should the commission retain an independent third party to conduct the auctions?

EGSI, TXU and AEP recommended that each affiliated PGC conduct its own auctions as the commission retains oversight of the auctions, and there is little incentive for the PGC to engage in discriminatory conduct. AEP further suggested that use of a third party may increase costs.

CPA stated that it believes the rule has adequate procedures in place to ensure non-discrimination.

PG&E and TNMP recommended that the commission retain a third party administrator, as such an entity could provide a single point of contact for capacity auction information, trading, and purchasing and would eliminate any concern about utilities gaining sensitive market information. Reliant disagreed and stated that such a requirement would only add costs. PG&E stated that if the commission allows utilities to conduct their own auctions, it should also preclude the utilities from using or disclosing any competitively sensitive information obtained from the bids prior to the disclosure of the bids to all auction participants.

The commission finds that retention of a third-party administrator by the commission is not necessary at this time as the prohibition on affiliates participating in the auctions minimize the potential for discriminatory behavior. The commission does agree with PG&E that the affiliated PGC should be precluded for using or disclosing any competitively sensitive information obtained from the bidding process prior to the disclosure of the bids to all auction participants. Additionally, the commission believes that there may be added benefits to the market if all affiliated PGCs jointly auction their entitlements such that the auctions are held in a common place or on a common web-site/screen. The commission encourages the parties in the implementation group to determine if it is feasible or desirable for the affiliated PGCs to jointly retain an auction administrator as well as resolve issues relating to the payment for this service. The commission notes that it has also added language in subsection (f)(2)(A) noting that affiliated PGCs, or groups of affiliated PGCs, may retain third party administrators to conduct the auctions.

Ancillary services provision from the capacity auction products

In addition to comments on these questions, several parties provided extensive comments on how the products should be revised to allow them to be used in ancillary services markets.

TNMP generally expressed a concern about the robustness of the ancillary services market and suggested that this rulemaking could be used to correct the potential market problem of the allowance of 100% self-provision on ancillary services. TNMP stated that limitations on dispatch effectively eliminated the potential for these products to be used in the ancillary service markets and suggested that the products would need call option capability and other specifics required by ERCOT for use as certain ancillary services. TNMP suggested that payments for other ancillary services could be shared on a load ratio basis with entitlement holders. TXU disagreed with this proposal, noting that a holder who had scheduled 100% of the entitlement would also receive payment for the ancillary services. TNMP also stated that if the rule could not be developed to achieve equivalent freedom of dispatch for entitlement holders as the generation owner, it would support a move to unit-specific auctions. TNMP supported the comments of CPA (discussed above) with respect to the use of the Responsibility Transfer Mechanism.

TXU suggested that the proposed products were primarily energy products that allow scheduling on a day-ahead basis and that the heat rates in the rule are not appropriate if the products are to be used for ancillary services. TXU also suggested language limiting the ancillary services to regulation up, regulation down, responsive reserve, and non-spinning reserve and noted that the rule should address the responsibility of the entitlement holder for settlement charges. TXU disagreed that the auction products should be modified to allow ancillary services capabilities and instead proposed a separate ancillary service product that would have scheduling and dispatch capabilities consistent with its intended use. TNMP argued that such a product would limit the dispatch of remaining entitlements. TXU stated that if the entitlements were to be used to provide ancillary services, it is important for the rule to address the responsibility for ERCOT settlement charges associated with the deployment of ancillary services scheduled from the entitlement.

AEP stated that it supported the further incorporation of ancillary services into the auction products and stated that entitlement holders should be allowed to schedule, on a day-ahead basis, up to a proportionate share of the ancillary services capabilities of the underlying units, but would require the use of company-specific heat-rates. AEP and EGSI also noted that provision of ancillary services for non-ERCOT utilities may be governed by the Federal Energy Regulatory Commission (FERC) transmission tariffs and urged the commission to allow flexibility.

Reliant proposed in reply comments to change the heat rate points to heat rate curves, in order for the products to be used in ancillary service markets. CPA generally supported those comments. PG&E generally supported the concept, but noted that several details needed to be discussed to make the proposal workable. PG&E also recommended that the commission retain the right to re-evaluate the heat rates in the future should it be necessary to do so.

In general, the commission believes that the market is best served by ensuring that the capacity auction products can be used for as many ancillary services as possible. However, it appears that this may require substantial changes to the rule on which not all parties have had the opportunity to comment, especially the heat-rate curve proposal set forth by Reliant. These changes could cause the products to lose the standardization and tradability that has been a major goal of this rule. Additionally, the ERCOT protocols are not at this time finalized, so attempts to incorporate those protocols into this rule may be premature. As such, the commission declines to modify the rule at this time but believes it is appropriate to establish an implementation task force to examine what further provisions may be needed to ensure that these products can be adequately used in ancillary services markets. Therefore, the commission has added language in subsection (e)(1)(E) of the rule providing that ancillary services may be provided from entitlements in accordance with procedures adopted by the commission, which will be developed in the implementation group. The implementation group should also address the ERCOT settlement issues raised by TXU. In general, the commission believes it is appropriate for this group to first examine the use of the gas-cyclic and gas-peaking products for ancillary services, as these products currently have the most scheduling flexibility, and only examine the use of the baseload and gas-intermediate products if it appears that it is critical to the market that these products also be used for ancillary services needs. In response to TNMP's concerns, and in order to ensure that these products can be adequately used for ancillary services needs or bid into the ancillary services markets, the commission has removed some of the scheduling requirements in subsection (e)(1)(C), (e)(5)(C)(iii), and (e)(5)(C)(iv) and noted that these products may be scheduled in accordance with scheduling procedures to be developed by the commission. In response to PG&E's comment about the commission retaining the right to modify the heat rates in the future, the commission notes that subsection (j) allows the commission to modify the products by order. To the extent the heat rates need to be modified, the commission believes this subsection provides that latitude.

Comments on specific sections of the rule:

§25.381(c) Definitions

AEP stated that the clear intent of the statute is to have affiliate PGCs auction entitlements to the utility's rate base generation fleet, and that as written, the rule could be interpreted to include utility-owned capacity that is not included in rate base, or capacity owned by unregulated subsidiaries. PG&E disagreed that capacity needed to be included in rate base to be included in the auction requirement and responded that AEP's proposed revision would also exclude capacity additions.

The commission finds that the plain reading of the statute suggests that any capacity currently owned and operated by the integrated utility is subject to the capacity auctions obligation, whether or not that capacity is included in rate base. Capacity currently owned and operated by unregulated affiliates of the utility is not subject to the auction requirements. This is consistent with the definition of affiliated power generation company in this section, which refers to the entity unbundled from the *electric utility*. No change to the definition has been made.

Reliant proposed modifying the definition of congestion zone to reference the ERCOT protocols.

The commission declines to make Reliant's change, as not all utilities subject to this rule are in ERCOT. However, the commission does broaden the definition to clarify that a congestion zone includes any area identified as a zone subject to transmission constraints.

§25.381(d)

TXU recommended that any divestiture count toward a utility's obligation for capacity auctions and suggested deletion of the requirement that such divestiture occur pursuant to a commission order. SPS stated that it did not disagree with TXU's revision, but reasserted that PURA does not require the sharing of the gains from sales of generation assets for utilities that have not sought stranded cost recovery. PG&E replied that the commission should reject TXU's recommendation.

The commission disagrees with TXU. The provision to allow certain utilities to meet their capacity auction requirements through divestiture is intended to keep faith with prior commission orders, decisions, and settlements in merger cases, and as such, is not arbitrary. The commission notes that other utilities that divest generation assets will have a lower amount of installed capacity to which the 15% requirement will be applied, and those utilities that divest to the point where they own less than 400 MW of capacity will be exempted by virtue of that limitation. No change to the rule has been made.

§25.381(e)(1)(B)

AEP recommended language clarifying that the minimum take for the gas-intermediate product applies in every hour.

The commission agrees with AEP's point but notes that this section already states that the minimum take is provided "seven days per week and 24 hours per day" and believes further clarification is not necessary.

§25.381 (e)(1)(F) Other Products

PG&E noted that an explicit good cause exception is not needed as commission substantive rule §25.3 already provides for the granting of exceptions to commission rules upon showing of good cause and that inclusion of an explicit exception in this rule may encourage utilities to seek their own products.

AEP noted that Southwest Electric Power Company (SWEPCO) and West Texas Utilities (WTU) may not have sufficient capacity to auction some of the products or terms required by the rule and supported the good cause exception. EGSI and AEP noted that non-ERCOT utilities may need to auction different products to recognize their unique circumstances.

The commission agrees with PG&E that §25.3 does provide a blanket good cause exception allowance and that the granting of such exceptions will defeat the purpose of the standardization of the products embodied in this rule. However, the commission believes that the inclusion of subsection (e)(1)(F) is valuable for informational purposes. The commission *does* recognize that utilities with relatively small amounts of generation subject to the auctions or FERC jurisdictional utilities may be unable to provide all of the products for all of the terms required by the rule. As such, the commission will entertain exceptions to the rule requirements for such utilities, but generally desires that these utilities auction the same products as outlined by the rule, if possible, but for one of the terms (*i.e.* monthly verses one-year terms). The commission recognizes that FERC jurisdictional utilities may have unique circumstances that may justify exceptions to the rule.

§25.381(e)(2)

TXU suggested that the term "settlement interval" be replaced with "scheduling period".

The commission adopts TXU's change.

§25.381(e)(3)

TXU requested that the commission consider the manner in which the affiliated PGC expects to use its generation units in determining the appropriate assignment of units to the products if a party objects to the utility's assignment.

The commission incorporates TXU's language.

§25.381(e)(4)

AEP expressed concern over the intent of the language indicating a requirement for the affiliated PGC to identify the point of the PGC's system from which the entitlement is dispatchable and recommended deletion of this provision

The commission declines to make AEP's change as this requirement may be needed in order to determine the cost responsibility for congestion costs. However, the commission does clarify that this requirement is to identify where on the transmission system the energy from the entitlements is delivered to the buyer.

TXU requested an amendment allowing an affiliated PGC to refuse to dispatch an entitlement if directed to do so by the ERCOT independent organization.

The commission agrees with TXU that if a PGC receives instructions from ERCOT to curtail generation due to a system emergency that such an order would override the dispatch of entitlements. TXU's recommended change has been made, but clarified to limit the dispatch only in the circumstance of a system emergency.

§25.381(f)(1)(A)

AEP noted that the determination of the 40% test is more complicated than suggested by the single sentence included in the rule and recommended the inclusion of a cross-reference to the price to beat rule and suggested additional language to make this section consistent with the determination that certain utilities may meet their capacity auction obligations through divestiture.

The commission agrees with AEP that language on the computation of the 40% threshold is properly detailed in the price to beat rule. The commission adds language to this section clarifying that the determination will be made pursuant to the commission's price to beat rule.

§25.381(f)(2)(A)

TXU recommended language to clarify that affiliated PGCs may outsource the auction administration functions.

The commission believes that allowing affiliated PGCs to conduct their auctions gives them full latitude in deciding whether or not to outsource such administration to a third-party. This section has been modified to reflect that concept. In general, the commission would strongly support multiple affiliated PGCs pooling their entitlements under a common auction and Internet site.

§25.381(f)(2)(B)

PG&E requested that the commission require that utilities disclose system outage information for the previous five years in the auction notice to assist bidders in evaluating the potential risks of outages. PG&E also noted that it is not necessary for the utility to determine which units will meet the product entitlements.

The commission notes that such information is not needed under the adoption of TXU's proposed firmness solution. Therefore, no change has been made to this section. However, the commission has required notice of historical planned outage rates in the initial filing to be made by the affiliated PGC under subsection (e)(3).

§25.381(f)(3)(A) and (B)

TXU suggested that too many entitlements will be auctioned too far ahead of the time they will be deployed and stated that liquidity would be better served by auctioning more entitlements closer to the months in which they will be used. Specifically TXU requested that 20% of entitlements be auctioned as two year strips, 20% as one year strips, 30% as discrete months (12 months in advance) and 30% as discrete months sold on a tri-annual basis.

The commission generally agrees that having 80% of available entitlement auctioned by October 2001 may be excessive. As such, the commission reduces the amount of two-year strips to 20% and increases the amount of discrete months sold on a tri-annual basis to 30%. Corresponding changes have been made to subsection (f)(3)(A) and (B).

§25.381(f)(3)(A)(i)

Reliant suggested that the initial auction should offer 30% of the entitlements as two one-year strips as opposed to a two year strip in order for the products to be appropriately incorporated into the true-up.

The commission agrees with Reliant and has made the suggested change, but notes that the two strips are to be auctioned jointly.

§25.381(f)(4)

AEP and EGSI noted that the "rounding up" provision should be revised as it will lead to an affiliated PGC auctioning more than the 15% required by statute which may be an unreasonable taking by the commission. AEP suggested language allowing the affiliated PGC to determine how to auction any remainder. TXU also recommended that the commission give latitude to the affiliated PGC in determining how to auction a remainder so that the affiliated PGC could assign the remainder to the product with the highest market value.

The commission notes that it will be extremely unlikely that utilities will be able to meet the exact 15% requirement in 25 MW blocks of capacity. Rounding down would clearly allow utilities to auction less than 15% of their capacity, which would be in clear violation of PURA. Allowing utilities discretion as to how they auction any remainder of less than 25 MW will result in limited products of a size different than the majority of entitlements. As the statute requires auction of *at least* 15% of a utility's capacity under commission rules, the commission finds that the requirement to auction slightly more than 15% conforms to the statute. The commission also notes that the affiliated PGC will receive compensation at a market price for all capacity sold at auction, including this slight increment over the 15%. The commission does agree that instead of automatically assigning the remainder to the next highest heat-rate product, a remainder should be assigned to the product valued highest by the market. As such, the existing language will be retained for purposes of the initial auction. Language has been added directing the affiliated PGC to assign the remainder to the product with the highest market value in the immediately preceding auction.

§25.381(f)(7)

TXU and AEP recommended that the opening bid price be based on the expected cost of providing the entitlements to the affiliated PGC. Cities agreed that a reservation price should be added to avoid the possibility of the price clearing at zero and suggested a methodology to develop reserve prices.

The commission is generally concerned that setting too high a reserve price will result in capacity going unsold, which would be contrary to PURA. PURA also specifically forbids the inclusion of any return on equity, which suggests that it was intended that a utility recover its variable costs of operation. The commission clarifies this section to allow the opening bid to include all variable costs of operation not recovered through the capacity bids or energy prices. As long as the opening bid is met, the affiliated PGC will recover no less than its variable costs of operation. The commission has also added clarifying language to note that an affiliated PGC is not obligated to accept bids for products below the opening bid price, but the PGC will be required to propose additional auctions of the other products in order to comply with the 15% requirement. In order to be consistent with the auction procedures, the commission has also replaced the term "reserve bid price" with "opening bid price".

§25.381(f)(8)

TXU suggested additional language to make the payment requirements stricter on buyers of entitlements.

The commission declines to adopt TXU's proposed changes. As discussed earlier, the credit standards are consistent with those approved by the commission in other proceedings.

§25.381(g)

AEP recommended deletion of the language that requires secondary buyers of entitlements to meet the same credit requirements as in the rule and noted that in energy markets today, buyers can resell products to other entities, but do not escape the responsibility of paying the initial seller. PG&E responded that such a requirement would place substantial credit requirements on the initial purchaser and may discourage participation in the initial auctions.

The commission agrees with PG&E, but notes as stated in the rule, that if a holder of an entitlement sells it to a party that does not meet the credit standards in the rule, that the initial holder of the entitlement would retain payment obligations to the seller. The commission believes that this arrangement will enhance the tradability of the entitlements.

§25.381(h)(1)

PG&E requested that the language regarding the gross-up of the capacity auction proceeds be clarified and suggested language to clarify that the proceeds from each product be summed before subtracting the amount from the gross-up from the fixed cost contribution from the ECOM model.

The commission has addressed this issue in its response to the comments on Question Number 7.

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

This new section is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2000) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction, and specifically pursuant to PURA §39.153, which requires that the commission establish rules that define the scope of the capacity entitlements to be auctioned, and the procedures for the auctions.

Cross Reference to Statutes: PURA §§14.002, 31.002, 39.153, 39.201, and 39.262.

§25.381. Capacity Auctions.

(a) **Applicability**. This section applies to all affiliated power generation companies (PGCs) as defined in this section in Texas. This section does not apply to electric utilities 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 competitiveness in the wholesale market through increased availability of generation and increased liquidity by requiring electric utilities and their affiliated PGCs to sell at auction entitlements to at least 15% of the affiliated PGC's Texas jurisdictional installed generation capacity, describing the form of products required to be auctioned, prescribing the auction process, and prescribing a true-up procedure, in accordance with PURA §39.262(d)(2).

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

(1) **Affiliated power generation company (PGC) –** For purposes of this section, an "affiliated PGC" refers to any affiliated power generation company that is unbundled from the electric utility in accordance with PURA §39.051. Until January 1, 2002, the term also includes an electric utility as defined in §25.5 of this title (relating to Definitions) that owns or operates for compensation in this

state equipment or facilities to generate more than 400 megawatts (MW) of electricity in this state until the electric utility has unbundled, but does not include river authorities.

(2) **Auction conclusion date –** The date on which the bids are due to be received and the winning bids in an auction are announced.

(3) **Business day –** Any day on which the affiliated PGC's corporate offices are open for business and that is not a banking holiday

(4) **Close of business –** 5:00 p.m., central standard or daylight savings time.

(5) **Congestion zone –** An area of the transmission network that is bounded by commercially significant transmission constraints or otherwise identified as a zone that is subject to transmission constraints, as defined by an independent organization.

(6) **Daily gas price –** The index posting for the date of flow in the Financial Times Energy publication "Gas Daily" under the heading "Daily Price Survey" for East-Houston-Katy, Houston Ship Channel.

(7) **Day-ahead –** The day preceding the operating day.

(8) **Installed generation capacity –** All potentially marketable electric generation capacity owned by an affiliated power generation company, including the capacity of:

(A) generating facilities that are connected with a transmission or distribution system;

(B) generating facilities used to generate electricity for consumption by the person owning or controlling the facility; and

(C) generating facilities that will be connected with a transmission or distribution system and operating within 12 months.

(9) **Power generation company (PGC) –** As defined in §25.5 of this title.

(10) **Starts –** Direction by the owner of an entitlement to dispatch a previously idle entitlement.

(11) **Texas jurisdictional installed generation capacity –** The amount of an affiliated PGC's installed generation capacity properly allocable to the Texas jurisdiction. Such allocation shall be calculated pursuant to an existing commission-approved allocation study, or other such commission-approved methodology, and may be adjusted as approved by the commission to reflect the effects of divestiture or the installation of new generation facilities.

(d) **General requirements**. Subject to the qualifications for auction entitlements and the auction process described in subsections (e) and (f) of this section, each affiliated PGC subject to this section shall sell at auction capacity entitlements equal to at least 15% of the affiliated PGC's Texas jurisdictional installed generation capacity. Divestiture of a portion of an affiliated PGC's Texas jurisdictional installed generation capacity will be counted toward satisfaction of the affiliated PGC's capacity auction requirement if and only if the divestiture is made pursuant to a commission order in a business combination proceeding pursuant to PURA §14.101, and after the transfer of the assets and operations to a third party.

(e) **Product types and characteristics.**

(1) **Available entitlements and amounts**. The following four products shall be auctioned as capacity entitlements under subsection (d) of this section. Each affiliated PGC shall auction an amount of each product in proportion to the amount of Texas jurisdictional installed generating capacity on the affiliated PGC's system that are the respective type of generating units. An affiliated PGC that owns generation in multiple congestion zones shall auction entitlements for delivery in each congestion zone. The amount of each product auctioned in each zone shall be in proportion to the amount of the respective type of generating units located in that zone, but the total shall not be less than 15% of the affiliated PGC's Texas jurisdictional installed generation capacity. The available entitlements for the months of March, April, May, October, and November of each year may be reduced in proportion to the average annual planned outage rate for the group of generating units associated with each type of entitlement. Entitlements shall be for system capacity.

(A) Baseload.

(i) Description. For each baseload capacity entitlement, the scheduled power shall be provided to the purchaser during the month of the entitlement seven days per week and 24 hours per day, in accordance with the scheduling requirements and limitations provided in paragraph (5)(C)(i) of this subsection.

(ii) Block size. Each baseload capacity entitlement shall be 25 MW in size.

(iii) Fuel price. The fuel cost owed to the affiliated PGC by the entitlement purchaser for the dispatched baseload power will be the average cost of coal, lignite, and nuclear fuel (in dollars per MWh) based on the company's final excess cost over market (ECOM) model as determined in the proceeding pursuant to PURA §39.201 as projected for the relevant time period. Electric utilities without an ECOM determination in their proceeding conducted pursuant to PURA §39.201 shall propose, for commission review, an average cost of fuel in a similar manner.

(iv) Starts per month. The purchaser of a baseload capacity entitlement must take power from the entitlement seven days per week and 24 hours per day and is therefore not permitted to direct the affiliated PGC to make any starts per month of baseload capacity entitlements.

(B) Gas – intermediate.

(i) Description. For each gas-intermediate capacity entitlement, 30% of the entitlement shall be provided to the purchaser during the month of the entitlement seven days per week and 24 hours per day with the remainder of the block scheduled as day-ahead shaped power, or hour ahead for ancillary services, in accordance with the scheduling requirements and limitations provided in paragraph (5)(C)(ii) of this subsection.

(ii) Block size. Each gas-intermediate capacity entitlement shall be 25 MW in size.

(iii) Fuel price. The fuel cost owed to the affiliated PGC by the capacity purchaser for the gas-intermediate capacity dispatched will be 9,900 British thermal units per kilowatt-hour (BTU/kWh) heat rate times the minimum kilowatt-hours (kWh) that must be taken for gas-intermediate capacity as required in paragraph (5)(C)(ii) of this subsection times the first-of-the-month index posted in the publication "Inside FERC" for the Houston Ship Channel for the month of the entitlement. For power dispatched above the minimum kWh required, the additional fuel price owed to the affiliated PGC will be 9,900 BTU/kWh times the kWh of gas-intermediate power dispatched pursuant to the entitlement above the minimum requirement times the daily gas price.

(iv) Starts per month. The purchaser of gas-intermediate capacity must take a minimum of 30% of the power from the entitlement and is therefore not permitted to direct the affiliated PGC to make any starts per month of gas-intermediate capacity entitlements.

(C) Gas – cyclic.

(i) Description. The gas-cyclic entitlement shall be flexible day-ahead shaped power and ancillary services.

(ii) Block size. Each gas-cyclic capacity entitlement shall be 25 MW in size.

(iii) Fuel price. The fuel price owed to the affiliated PGC by the capacity purchaser for gas-cyclic capacity dispatched will be 12,100 BTU/kWh times the kWh of the gas-cyclic power dispatched under the entitlement times the daily gas price.

(iv) Starts per month and associated costs. The purchaser of gas-cyclic capacity shall be entitled to direct the selling affiliated PGC to make up to the amount of starts per month of each entitlement of gas-cyclic capacity allowed by the scheduling procedures adopted by the commission.

(D) Gas – peaking.

(i) Description. The gas-peaking entitlement shall be intra-day power and ancillary services.

(ii) Block size. Each gas-peaking capacity entitlement shall be 25 MW in size.

(iii) Fuel price. The fuel price owed to the affiliated PGC by the purchaser for gas-peaking capacity dispatched will be 14,100

BTU/kWh times the kWh of the gas-peaking power dispatched under the entitlement times the daily gas price.

(iv) Starts per month and associated costs. The purchaser of gas-peaking capacity shall be entitled to direct the selling affiliated PGC to make unlimited starts per month of each entitlement of gas-peaking capacity.

(E) Ancillary services. The owner of a capacity entitlement may use it to meet ancillary services needs, if the needs may be met in a manner that is consistent with procedures developed by the commission. The amount of ancillary services available will be in proportion to the ancillary services capabilities of the units that are used to define the capacity offered in the different entitlement products.

(F) Other products. Upon showing of good cause by the affiliated PGC and approval by the commission, an affiliated PGC may propose to auction entitlements different from those described in this subsection, including unit specific capacity.

(2) **Forced outages.** If all units providing capacity to an entitlement product experience a forced outage or an emergency condition prevents or restricts the ability of an affiliated PGC to dispatch a particular entitlement product, the entitlements of that product may be reduced in proportion to the percentage reduction to the grouping of units assigned to that entitlement; provided that such reductions in availability of any single entitlement do not exceed 2.0% of the total

monthly energy available from the entitlement. Notification of any such reductions will take place prior to the next scheduling period.

(3) **Generation units offered**. Within 60 days after the effective date of this section, the affiliated PGC shall file with the commission its proposed assignment of each of the affiliated PGC's power generation units to one of the four available product entitlements identified in paragraph (1) of this subsection, and the resulting amount of each type of entitlement to be auctioned. As part of this filing, the affiliated PGC shall provide planned outage histories for the years 1998, 1999, and 2000 for each generating unit to be used to calculate the average annual planned outage rate for each group of generating units. Interested parties shall have 30 days in which to provide comments on the utility's proposed assignments. If no comments are received, the utility's assignment shall be deemed appropriate. If any party objects to the utility's proposed assignments, the commission shall determine the appropriate assignment considering the manner in which the affiliated PGC expects to use such generation units.

(4) **Obligations of affiliated PGC**. The affiliated PGC shall dispatch entitlements only as directed by the holder of the entitlement in accordance with paragraph (5)(C) of this subsection. The affiliated PGC may not refuse to dispatch the entitlement and may not curtail the dispatch of an entitlement unless expressly authorized by this section or directed to do so by the independent organization in order to alleviate a system emergency. The affiliated PGC shall specify in its

notice provided pursuant to subsection (f)(2)(A) of this section the point on the transmission system where energy from each entitlement is delivered to the buyer.

(5) **Purchaser's rights and duties.**

(A) No possessory interest. The entitlements sold at auction shall include no possessory interest in the unit or units from which the power is produced.

(B) No possessory obligations. The entitlements sold at auction shall include no obligation of a possessory owner of an interest in the unit or units from which the power is produced.

(C) Scheduling. The purchaser shall have the right to designate the dispatch of the entitlement, subject to paragraph (2) of this subsection. In addition, the following scheduling limitations apply based upon the type of capacity entitlement being scheduled.

(i) Baseload. Baseload capacity entitlements must be scheduled at a minimum of 80% of the block size. A baseload entitlement purchaser may vary the amount of energy scheduled between 80% and 100% of the block size on a day-ahead basis. Such schedule changes must be in hourly increments of no more than +/- 10% of the block size per hour. Baseload capacity entitlements can be scheduled only on a day-ahead basis. Nothing in this paragraph affects the right or obligation of the owner of a baseload entitlement to schedule the delivery of power from the entitlement through the independent organization.

(ii) Gas – intermediate. Gas-intermediate entitlements can be scheduled on a day-ahead basis. Gas-intermediate ancillary services can be scheduled on a day-ahead or hour-ahead basis. An entitlement must be scheduled at a minimum of 30% of the block size, with a maximum allowable hourly swing of +/- 25% of the block size. Other than for ancillary services, there shall be no hour-ahead scheduling for intermediate capacity entitlements.

(iii) Gas – cyclic. Gas-cyclic entitlements shall be scheduled consistent with the scheduling procedures developed by the commission.

(iv) Gas – peaking. Gas-peaking entitlements shall be scheduled consistent with the scheduling procedures developed by the commission.

(D) Credit requirements.

(i) Standards. Entities submitting bids must satisfy one of the following credit standards:

(I) The entity holds an investment grade credit rating (BBB- or Baa3 from Standard and Poor's or Moody's respectively or an equivalent);

(II) The entity provides an escrowed deposit equal to the bid amount plus the amount that would be paid to exercise the entitlement for the shorter of the duration of the entitlement or three months at the minimum required dispatch;

(III) The entity provides a letter of credit or surety bond equal to the bid amount plus the amount that would be paid to exercise the entitlement for the shorter of the duration of the entitlement or a rolling three-month period at the minimum dispatch required, irrevocable for the duration of the entitlement;

(IV) The entity provides a guaranty from another entity with an investment grade credit rating; or

(V) The entity makes other suitable arrangements with the affiliated PGC, provided that the affiliated PGC makes such arrangements available on a non-discriminatory basis.

(ii) All cash and other instruments used as credit security shall be unencumbered by pledges for collateral.

(iii) In the event the holder of the entitlement initially relied on its investment grade credit rating but subsequently loses it during the entitlement period, the holder of the entitlement must provide alternative financial evidence within ten days.

(iv) The holder of the entitlement must notify the affiliated PGC of any material changes that impact the financial requirement contained in the credit standards.

(v) In the event the holder of the entitlement fails to meet or continue to meet its security requirement, the entitlement shall revert to the affiliated PGC and shall be auctioned in the next auction for which notice can be provided of the sale of the entitlement pursuant to subsection (f)(2)(A) of this section.

(f) **Auction process.**

(1) **Timing issues.**

(A) Frequency of auctions.

(i) Initial auction. The initial capacity auction shall be concluded on or before September 1, 2001.

(ii) Subsequent auctions. Capacity auctions subsequent to the initial auction shall be concluded on March 15, 2002, July 15, 2002, September 1, 2002, and November 15, 2002. Auctions conducted in the years following 2002 will be concluded in the same months and day of the month, as the auctions conducted in 2002 (or in the event that date falls on a weekend or banking holiday, on the first business day before the weekend or banking holiday).

(iii) Termination of the capacity auction process. The obligation of an affiliated PGC to auction entitlements shall continue until the earlier of 60 months after the date customer choice is introduced or the date the commission determines that 40% or more of the electric power consumed by residential and small commercial customers within the affiliated transmission and distribution utility's certificated service area before the onset of customer choice is provided by nonaffiliated retail electric providers. The determination of the 40% threshold shall be as prescribed by the commission's rule relating to the price to beat.

(B) Auction conclusion.

(i) Receipt of bids. In order for an affiliated PGC that is auctioning capacity to consider a bid, the bid must be received by that affiliated PGC by close of the round for which the bid is to be submitted.

(ii) Concluding each individual auction. The affiliated PGC shall provide notice of the winning bid(s) to auction participants and the commission by the close of business on the auction conclusion date.

(iii) Confidentiality and posting of bids. The affiliated PGC shall only provide the quantities requested by bidders during the auction. The affiliated PGC shall designate non-marketing personnel to evaluate the bids and persons reviewing the bids shall not disclose the bids to any person(s) engaged in marketing activities for the affiliated PGC or use any competitively sensitive information received in the bidding process. Upon announcement of the winning bids, the affiliated PGC shall provide the commission and all auction participants with all of the bids, but shall not divulge the identity of any particular bidders. Upon specific request by the commission, and under standard protective order procedures, the utility shall provide the identity of the bidders to the commission.

(2) **Auction administration**.

(A) Each auction shall be administered by the affiliated PGC selling the entitlement. An affiliated PGC or group of affiliated PGCs may retain the services of a qualified third-party to perform the auction administration functions.

(B) Notice of capacity available for auction.

(i) Method of notice. At least 60 days before each auction conclusion date, each affiliated PGC offering capacity entitlements at auction shall file with the commission notice of the pending auction. The commission shall provide on its Internet site a continually updated list of pending auctions for each affiliated PGC subject to this section.

(ii) Contents of notice. Such notice shall include the auction conclusion date, the date and time by which bids must be received for the first round, and the types, quantity (number of blocks), congestion zone, and term of each entitlement available in that auction. The notice shall also include the formula that will be used to adjust the price of entitlements between rounds of the auction. The affiliated PGC shall also specify which power generation units will be used to meet the entitlement for each type of entitlement to be auctioned. If baseload entitlements are being auctioned, the utility shall also specify the fuel cost described in subsection (e)(1)(A)(iii) of this section at the time of the auction. If gas intermediate, gas cyclic, or gas peaking entitlements are being auctioned, the utility shall specify the fuel service cost.

(3) **Term of auctioned capacity.**

(A) Initial auction. For the initial auction on September 1, 2001, each entitlement will be one month in duration, with:

(i) Approximately 20% of the entitlements auctioned as two one-year strips with the strips auctioned jointly (the 12 months of 2002 and 2003),

(ii) Approximately 30% of the entitlements as one-year strips (the 12 months of 2002), and

(iii) Approximately 20% of the entitlements as discrete months for each of the 12 months of 2002 (January through December of 2002)

(iv) Approximately 30% of the entitlements as discrete months for the first four months of 2002 (January through April of 2002).

(v) Reductions in the amounts of entitlements available during the months of March, April, May, October, and November of each calendar year shall be accounted for in the entitlements offered as discrete months.

(B) Subsequent auctions.

(i) The auction on March 15 of a year will auction approximately 30% of the entitlements as the discrete months of May through August of that year.

(ii) The auction on July 15 of a year will auction approximately 30% of the entitlements as the discrete months of September through December of that year.

(iii) The auction on September 1 of a year will auction:

(I) Approximately 30% of the entitlements as the one-year strips for the next year, and

(II) Approximately 20% of the entitlements as discrete months for each of the 12 calendar months of the next year.

(iv) The auction on November 15 of a year will auction approximately 30% of the entitlements as the discrete months of January through April of the next year.

(v) Reductions in the amounts of entitlements available during the months of March, April, May, October, and November of each calendar year shall be accounted for in the entitlements offered as discrete months.

(vi) In June of 2003, an evaluation will be made by the commission as to the need for another set of two-year strips (the 24 months of 2004 through 2005). If such term is deemed to be necessary, the next set of two-year strips will be auctioned on September 1 of 2003. If such term is not deemed to be necessary, then subsequent auctions will auction 50% of entitlements over one-year strips and 50% of the entitlements as discrete months.

(C) Modification of term. If the auction is for a one-year or two-year strip term and the affiliated retail electric provider (REP) expects to reach the 40% load loss threshold in paragraph (1)(A)(iii) of this subsection, the affiliated PGC may request a shorter term strip by providing evidence of the loss of customer load. Similarly, prior to an auction for the next four available months, an affiliated PGC may request to not auction months in which it projects reaching the 40% threshold. Such filings shall be made 90 days before the auction conclusion date. An affiliated PGC that will satisfy its auction requirements through divestiture, as described in subsection (d) of this section may petition the commission to set an appropriate term for entitlements. The affiliated PGC may not adjust the amount or length of an entitlement to be auctioned except as authorized by the commission.

(4) **Quantity to be auctioned.**

(A) Block size and number of blocks. The block size of the auctioned capacity entitlement is 25 MW. The affiliated PGC shall divide the amount determined for each product described in subsection (e)(1) of this section by 25 to determine the number of blocks of each type to be auctioned.

(B) Divisibility. For purposes of the initial auction, if the amount to be auctioned for an affiliated PGC for a particular product is not evenly divisible by 25, the remainder shall be added to the next highest heat-rate product available (in the order of baseload, gas-intermediate, gas cyclic, and gas peaking). The remainder for the highest heat-rate product available shall then be rounded up to 25. For subsequent auctions, a remainder shall be added to the product most highly valued in the immediately preceding auction and shall increase by one the number of entitlements of that product.

(C) Total amount. The sum of the blocks of capacity auctioned shall total no less than 15% of the affiliated PGC's Texas jurisdictional installed generation capacity.

(5) **Bidders**. For each auction, potential bidders must pre-qualify by demonstrating compliance with the credit requirements in subsection (e)(5)(D)(i) of this section in advance of submission of a bid.

(6) **Bidding procedures.** For purposes of this section, the term "set of entitlements" shall refer to the pairing of a particular product with a term. For example, a quantity of baseload products sold as a one-year strip for 2002 would be a set of baseload-annual 2002 entitlements, while a quantity of baseload products sold as the discrete month of July 2002 in a quantity of ten would be a set of baseload-July 2002 entitlements.

(A) Method of auction. Each auction shall be a simultaneous, multiple round, open bid auction. Rounds shall be held open for a reasonable amount of time to allow bidders to submit bids while still allowing efficient conclusion of the auction.

(i) First round. For the first round of the auction, the affiliated PGC will post the opening bid price determined in accordance with paragraph (7) of this subsection for each of set of entitlements available for purchase at the auction. Each bidder will specify the number it wishes to purchase of each set of entitlements at the opening bid price(s). If the total demand for a set of entitlements is less than the available quantity of the set of entitlements, the price for each of the entitlements in the set will be the opening bid price and each bidder in the round will receive all of the entitlements in the set they demanded. Any remaining entitlements of the set will be held for future auction as noticed by the affiliated PGC in accordance with its notice given pursuant to paragraph (7) of this subsection.

(ii) Subsequent rounds. If the total demand for a set of entitlements is more than the available quantity, the affiliated PGC will adjust the price upward. Bidders shall then submit bids for the quantities they wish to purchase of each set of entitlements at the new price(s). Subsequent rounds shall continue until demand is less than or equal to supply for each set of entitlements. The auction then closes and the market clearing price for each set of entitlements is set at the last price for which demand exceeded supply. Bidders shall then be awarded the entitlements they demanded in the final round, plus a pro-rata share of any entitlements they demanded in the next to last round.

(B) Activity rules.

(i) A bidder must bid in the first round for a particular entitlement to participate in subsequent rounds.

(ii) A bidder may not bid a greater quantity than it bid in a previous round for a particular entitlement.

(C) Mechanism for auction. Each affiliated PGC shall conduct the auction over the internet on a secure web page(s) and shall assign a password and bidder's number to each entity that has satisfied the credit requirements in this section.

(7) **Establishment of opening bid price.** Within 60 days of the effective date of this section, the affiliated PGC may file with the commission a methodology for determining an opening bid price for each type of entitlement, if needed, based on the utility's expected variable cost of operation, but excluding any return on equity. The opening price may not include any cost included in the fuel price to be paid by entitlement winners, nor any cost being recovered by its affiliated transmission and distribution utility through non-bypassable delivery charges, but

may recover variable costs not included in the fuel prices, such as fuel service costs and start-up fees. Parties shall have 30 days after filing to challenge the methodology. In the notice provided pursuant to paragraph (2)(B)(i) of this subsection, the affiliated PGC may make available an opening bid price calculated pursuant to the commission-approved methodology for each type of entitlement to be offered for sale at auction. The affiliated PGC shall not be obligated to accept any bid for a product less than the opening bid price, but shall notify the commission that the opening bid price was not met. The affiliated PGC shall, in its notice, propose an auction of additional entitlements of the products for which the minimum bid was met in order to comply with the 15% requirement.

(8) **Results of the auction.** The results of the auction shall be simultaneously announced to all bidders by posting on the affiliated PGC's auction web site with posting of the market clearing price for each set of entitlements.

(g) **Resale of entitlement.** The winners of an entitlement may resell the entitlement (or portions thereof) to any eligible purchaser except the affiliated REP of the affiliated PGC that originally auctioned the entitlement. The third party must meet the same credit requirements that had been required of the initial bid winner. Alternatively, a winner may assign the entitlement to a third party that does not meet the associated credit requirements provided that the original winner retains all payment and other related obligations. Owners of entitlements may direct the dispatch of those entitlements to any lawful purchaser of electricity, including the affiliated REP.

(h) **True-up process.**

(1) For each month beginning on February 1, 2002 to the month following the date a final order is issued in the PURA §39.262 proceeding, the affiliated PGC shall reconcile, and either credit or bill to the transmission and distribution utility, any difference between the price of power obtained through the capacity auctions under this section and the power cost projections that were employed for the same time period in the Excess Cost over Market (ECOM) model to estimate stranded costs for the affiliated PGC in the PURA §39.201 proceeding.

(2) An affiliated PGC that does not have stranded costs described by PURA §39.254 is not required to comply with paragraph (1) of this subsection.

(i) **True-up process for electric utilities with divestiture.** If an affiliated PGC meets its capacity auction requirements through a divestiture as allowed by subsection (d) of this section, the proceeds of the divestiture shall be used for purposes of the true-up calculation.

(j) **Modification of auction procedures or products**. Upon a finding by the commission that the auction procedures or products require modification to better value the products or to better suit the needs of the competitive market, the commission may, by order, modify the procedures or products detailed in this rule.

(k) **Contract terms.** Parties shall utilize a standard agreement adopted by the commission in detailing the terms, conditions, and obligations of the selling and buying parties.

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 §25.381 relating to Capacity Auctions is hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 14th DAY OF DECEMBER 2000.

PUBLIC UTILITY COMMISSION OF TEXAS

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Chairman Pat Wood, III

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Commissioner Judy Walsh

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Commissioner Brett A. Perlman