PROJECT NO. 24492

RULEMAKING PROCEEDING TO REVISE SUBSTANTIVE RULE §25.381, CAPACITY AUCTIONS	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING AMENDMENT TO §25.381, CAPACITY AUCTIONS, AS APPROVED AT THE MAY 23, 2002 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts an amendment to §25.381 relating to Capacity Auctions with changes to the proposed text as published in the January 18, 2002 *Texas Register* (27 TexReg 425). The amendment implements the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §39.153 (Vernon 1998, Supplement 2002), 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. PURA Chapter 39, Restructuring of Electric Utility Industry, became effective September 1, 1999, as part of Senate Bill 7, 76th Legislative Session (SB 7), 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 amendment is adopted under Project Number 24492.

The commission received comments on the proposed amendment from Alkera, Inc. (Alkera); Central Power and Light Company (CPL), West Texas Utilities Company (WTU), and Southwestern Electric Power Company (SWEPCO) (CPL, WTU, and SWEPCO collectively known as AEP); Coral Power, L.L.C. (Coral); Dynegy Inc. (Dynegy); Tenaska Power Services Company (Tenaska); Entergy Gulf States, Inc. (EGSI), Entergy Solutions Ltd., Entergy Solutions

Select Ltd., Entergy Solutions Essentials, Ltd. (collectively the Entergy REPs); Green Mountain Energy Company (GMEC); New Power Company (New Power); Office of Public Utility Counsel (OPUC); Steering Committee of Cities Served by TXU (Cities); Reliant Energy, Inc. (REI); Reliant Resources, Inc. (RRI); Southwestern Public Service Company (SPS); TXU Generation Company LP (TXUG), and TXU Energy Trading Company LP (TXUE) (TXUG and TXUE collectively referred to here as TXU).

Comments on specific questions posed in the preamble:

Question Number 1: In regards to ongoing creditworthiness:

a. Should a seller be allowed to require additional security from a purchaser, if the creditworthiness or financial responsibility of the purchaser becomes unsatisfactory, in the reasonable judgement of the seller, at any time during which the entitlement is in effect?

Sellers of entitlements (AEP, EGSI, REI, and TXU) supported allowing additional security to be required from a buyer. Entergy REPs, OPUC, and Cities supported the position of the sellers, but expressed the same concerns that led other parties to oppose the additional security. Coral, Dynegy, Tenaska, GMEC, New Power, and RRI opposed allowing additional security to be required mainly because they felt that allowing additional security "in the reasonable judgement of the seller" gave too much subjective power to the seller and would permit discrimination. AEP proposed new language to allow an affiliate PGC to request additional performance assurance if the entitlement holder's creditworthiness becomes unsatisfactory. EGSI added that it is appropriate to request a reasonable amount of additional financial security from buyers to ensure that they are able to meet their continuing obligation with respect to purchased products. TXU and REI's comments closely resembled the sentiments of AEP and EGSI with the addition that REI believed that a seller would not invoke the "reasonable judgement" provision arbitrarily, because if a seller did not act reasonably it would be in breach of its agreement and would be liable to the buyer for damages.

The Entergy REPs stated that additional security from the purchaser should be allowed if the financial security of the purchaser materially changes, as long as the criteria for requiring additional security are clearly identified in the seller's credit requirements and there are clear parameters for exercising "reasonable judgement." OPUC and Cities echoed this view but felt that "reasonable judgement" should be quantified by an appropriate formula to prevent abuse by sellers. Coral, Dynegy, and Tenaska stated that sellers should not be permitted to demand unlimited credit assurance without defined and definitive causes, such as a credit downgrade. GMEC and New Power added that the repercussions of leaving the decision to the affiliated PGC could be severely detrimental to the market for a number of reasons, including placing parties on unequal footing in trades. RRI commented that the "reasonable judgement" provision is arbitrary and that even objective standards should prevent an overdependence on input from one source of credit information.

In reply comments, AEP and TXU stated that parties that fear the affiliated PGC could unilaterally impose onerous credit requirements upon the other party have not recognized that there would be significant constraints on the PGC's actions. The EEI/NEMA contract itself would deem an unreasonable request for assurances as a breach of contract, triggering significant penalties. Coral argued that the additional credit provision is not accepted by Coral in other commercial transactions, nor do they believe it is accepted by the majority of purchasers in such transactions. Coral also noted that legal remedies for an unwarranted demand for additional security are problematic, because litigation is costly and slow. EGSI explained that sellers are accountable to the commission and are not likely to abuse the credit provision by treating the same counterparties differently in the capacity auction than they would in bilateral market transactions. RRI commented that it was concerned that "reasonable" judgements and additional credit requirements imposed unexpectedly and without objective standards would increase credit related financial burdens. RRI contended that credit requirements should be specific, fair, and not create unnecessary barriers to capacity auction participation. TXU argued that the right of a seller to ask for credit assurances is not only standard practice in the energy industry, it is a vital right considering that capacity auction sellers are required to offer unsecured credit to potential buyers pursuant to the standards set forth in the rule. TXU stated that it is not true that capacity auction sellers could use the credit assurances provision at their whim to keep certain non-investment grade entities out of the auctions.

b. *What are the positives and negatives associated with allowing additional security to be required from the purchaser?*

AEP stated that the positives would be allowing the risk of non-performance to be allocated directly to the party causing the risk. The Entergy REPs commented that a positive would be that the additional security would provide stability to the auction process and would mitigate the risk of default by the purchaser. REI opined that allowing additional security provides the seller necessary protection against changed circumstances during the entitlement period. TXU commented that without the additional security, sellers could be left with significant unpaid capacity auction debt or pennies on the dollar for unsecured capacity auction debts. This would defeat the purpose of the capacity auctions and endanger the financial standing of capacity auction sellers. GMEC commented that potential negatives included the facts that asymmetry of this sort creates an opportunity for the affiliated PGC to distort the number of bidders and the type of bidders, and that allowing the affiliated PGC to increase the deposit requirement does not have equal impact on bidders. An additional dollar of escrow or surety bond affects a company more than an additional dollar applied against a credit rating, which GMEC states has potential liquidity implications for the auctions. New Power added that allowing sellers to exercise their "reasonable judgement" might allow sellers to squeeze out certain REPs and in effect discriminate against companies that do not have an investment credit rating, or discriminate for other arbitrary and capricious reasons. RRI stated that the provision could serve as a barrier to entry for the new market participants and lessen the interest of those currently active in the capacity auction process.

The commission finds arguments on both sides of this issue persuasive. The commission agrees with capacity auction sellers that they are required to participate in the capacity auctions and that there is risk that the purchasers of capacity auction entitlements will not be able to pay for those entitlements due to circumstances that change after the auction is held. However, the commission also agrees with the purchasers of capacity auction entitlements that allowing sellers the ability to require additional credit at any time for any reason is too much subjective power to grant to the sellers, as it could lend itself to discrimination based on current or prior affiliations. The commission concludes that capacity auction sellers should be allowed to require additional security from entitlement purchasers only if the financial condition of the purchaser materially changes after the auction, and if the criteria for determining a material change and the form of additional security are clearly identified in the seller's credit requirement provisions of the Agreement. Language has been added to the rule to reflect this decision.

c. Should an additional security provision be in place for the seller as well as the purchaser?

The parties were again split on this issue. AEP, EGSI, Entergy REPs, and REI were against the purchaser being able to require additional security from the seller. Coral, Dynegy, Tenaska, GMEC, New Power, and RRI, as potential buyers, opined that purchasers should be allowed to request additional security from sellers; OPUC and Cities supported this position. The position generally echoed by Coral, Dynegy, Tenaska, GMEC, New Power, OPUC, Cities, and RRI was that buyers and sellers should be afforded equal, symmetrical credit protections through objective credit standards. In their view, the buyer is subject to as much risk as the seller in these auctions; therefore, symmetry of deposit requirements is appropriate. Coral, Dynegy, and Tenaska also pointed out that entitlement holders face a significant credit risk. In the short run, buyers of entitlements bear the risk that generation requested pursuant to an entitlement will be curtailed in the middle of a schedule resulting in the entitlement holder being liable for the imbalance charges assessed by the Electric Reliability Council of Texas (ERCOT). In the long run, the capacity purchased could be unavailable for a prolonged period. In addition to not receiving the service that it has paid for, the entitlement holder would also be unable to meet its commitments to sell electricity to its customers without purchasing that power from other sources. In addition, GMEC deemed that the draft language seems equipped to protect the seller from buyer's default in payment, but needs to add symmetry to the transaction by giving protection to buyers from the financial impact of seller's default. GMEC proposed language that would hold the affiliated PGC responsible for any assessments from ERCOT for imbalanced schedules, failure to procure ancillary services, or any other charges due to the failure of the affiliated PGC to fulfill the auctioned obligation.

AEP, EGSI, Entergy REPs, and REI stated that no additional security should be given to the buyer as the sellers have a legal obligation to perform and buyers will weigh the perceived risk into their bids.

In reply comments, Coral, Dynegy, and Tenaska noted that sellers argue that if buyers are in any way dissatisfied with the terms or bid prices they can simply choose to not participate in the capacity auctions. Coral, Dynegy, and Tenaska contended that this is the very reason the rule should require bilateral credit. The absence of symmetrical, bilateral credit protection in the capacity auctions would provide a significant incentive for buyers to choose products available in the commercial market over those available in the capacity auctions. Coral, Dynegy, and Tenaska commented that certain parties argue that buyers have no risk because sellers' regulatory compliance will assure performance of their obligations. However, if a credit event prevents a seller from generating, no matter how badly that seller may wish to comply with the commission's regulations, it will be unable to do so. Regulatory compliance will take place only when sellers are financially and economically able to comply. In terms of implementation, Coral, Dynegy, and Tenaska explained that stakeholders would select the cover sheet options such that credit protections afforded only to sellers would be made applicable to both sellers and buyers. They propose that the same ERCOT Qualified Scheduling Entity (QSE) credit standards that have been used to quantify the security requirements applicable to buyers also be made applicable to sellers. Unrated sellers may have to obtain guarantees from a rated parent or affiliate if they do not meet minimum financial requirements. This would not expose them to additional expense.

While the commission is sympathetic to the plight of buyers regarding the risk of a seller's default, the commission declines to impose the additional cost associated with meeting bilateral credit requirements on the capacity auction sellers. However, the commission finds that an entitlement holder shall be allowed to request credit assurances from the entitlement seller in the event of a downgrade event for the entitlement seller which would put the entitlement holder at risk. If a downgrade event occurs, the entitlement holder may request credit assurance from the seller in a commercially reasonable manner. If the seller does not provide the credit assurance within three business days of receipt of notice, then the entitlement holder shall have the right to suspend performance as prescribed in the Agreement (and thus suspend payments for energy not yet delivered) and may ultimately terminate the Agreement after the suspension period. Language reflecting these decisions has been incorporated into the rule. A downgrade event for the seller shall be structured, on the cover sheet of the Agreement, in the same fashion as is currently employed for the entitlement holder, except that the downgrade event is defined as any lowering of the seller's credit rating, and not below a particular threshold.

Question Number 2: In regards to auction mechanics:

a. Should non-Electric Reliability Council of Texas, Inc. (ERCOT) and non-stranded cost companies be allowed to have different auction processes or mechanics from other companies?

AEP strongly supported the ability of non-stranded cost companies to devise commercially reasonable auction processes and products. AEP added that for non-stranded cost companies, the commission's sole goal should be to ensure that the affiliated PGC has designed its auction process to sell 15% of the Texas jurisdictional installed generation capacity. AEP argued that the proceeds from the capacity auctions for such companies go directly to their bottom line and the commission should grant such companies the ability to structure the auctions in a way that fits management's view of the market. In its reply comments, AEP clarified that all it is seeking is an explicit recognition that there is a difference between the amount of regulatory review required for stranded cost companies as opposed to non-stranded cost companies.

Coral, Dynegy, Tenaska, EGSI, OPUC, Cities, RRI, and TXU were generally opposed to allowing this type of flexibility in the auction process. Coral, Dynegy, and Tenaska simply stated that the auction should be conducted according to the same terms and procedures utilized in the ERCOT auction. EGSI offered that the capacity auction rule and mechanics currently offer sufficient uniformity for efficient auctions statewide, and noted in reply comments that while not opposed to the overall philosophy of tailoring product offerings, it does not anticipate offering products other than those defined in the proposed rule. GMEC explained that uniform auctions would encourage as many bidders as possible and perhaps "ramp up" retail competition in non-ERCOT regions. OPUC and Cities argued that it did not make sense to take a step backward to non-standardized auction processes. In addition they stated that no company should be allowed to offer products inferior to or different from products other companies are offering, except to the extent some differences already exist. RRI noted that there is no legislative basis for allowing non-ERCOT and non-stranded cost companies to have different auction processes or mechanics. TXU echoed the statements of OPUC and Cities and stated that it saw no reason why non-ERCOT and non-stranded cost companies should not also have to follow the uniform processes and mechanics, with the only exception being the differences already delineated in the proposed amendments to the capacity auction rule. TXU commented in its reply comments that in order to achieve a true liquid market through the Texas capacity auctions, the capacity auction products must be tradable. Allowing some capacity auction sellers to design and sell alternative capacity auction products would interfere with tradability of capacity auction products and would stunt the growth of a liquid market. TXU also noted in reply comments that if the commission finds that there is some value in allowing divergent capacity auction processes and products, then it is only equitable to allow all of the capacity auction sellers to have different processes and products.

b. What are the potential gains to allowing differing processes or mechanics and what potential detriments exist in regards to efficiency and loss of standardization?

AEP explained that the benefits would include the ability to tailor both products and procedures to the marketplace in ways that more clearly meet market demands without causing inefficiencies from the loss of standardization between ERCOT and non-ERCOT companies. Coral, Dynegy, and Tenaska offered that, to the extent the auctions mirror the ERCOT auctions, REPs will face less of a burden to participate in these auctions. If the auctions are different, REPs will require additional resources to participate, which will reduce participation and liquidity. GMEC added that differences in auction mechanics make participation more difficult and more costly, which could be a barrier to the bidder's entry into the auction, especially in markets that are less robust. GMEC also noted that the benefits of continuity are significant to markets all over the state, including those areas that have yet to open for competition. OPUC and Cities stated that a loss of standardization will impose greater burden on bidders who would have to learn multiple sets of rules to bid into multiple auctions instead of a single set of auction rules. This unnecessary complication could lead to confusion on the day of the auction if bidding on both ERCOT and non-ERCOT products. RRI largely echoed these sentiments in stating that differing mechanics could result in market confusion that results in less participation, lost efficiency, and loss of standardization as overlapping or contradicting sets of rules and regulations may cause disputes among the players and lead to lengthy and extensive dispute resolution or litigation.

The commission finds that the arguments of AEP are not persuasive. The commission agrees with the other commenting parties that there is no reason to allow any company to offer products inferior to or different from products other companies are offering, except to the extent differences already exist. The commission finds that allowing differing mechanics could result in market confusion, resulting in potential losses in participation, efficiency, and standardization which could lead to overlapping or contradictory rules and disputes. The commission disagrees with AEP and finds that all capacity auction sellers should be subject to the same amount of regulatory review to ensure that an affiliated PGC has auctioned 15% of its Texas jurisdictional installed generation capacity. Allowing differing auction mechanics would also create a regulatory burden in determining that an affiliated PGC has in fact met its auction requirement. The commission declines to make the recommended changes proposed by AEP.

Question Number 3: Should the Power Generating Companies (PGCs) involved in the capacity auction use a common auction platform?

None of the parties representing buyers or sellers of capacity auction products supported the use of a common platform. AEP explained that within ERCOT, only WTU (which will only offer a few products and a few entitlements) will be on a different auction platform (after CPL's divestiture of 1,354 megawatts (MW) of generation capacity in 2002). AEP added that requiring all companies to use the same platform would mean additional programming and transition costs for the companies that do not use that platform already. If an all-new platform is adopted, the old software and the associated expense of the old platform would become stranded. AEP contended that before such a cost is imposed, the commission should determine that the benefits significantly exceed the costs. EGSI argued that no buyer raised a concern or complaint regarding EGSI's auction process, which suggests that buyers were able to negotiate the process with relative ease. EGSI offered that while a common auction platform might offer some limited efficiency to buyers who participate in multiple auctions, there does not appear to be any assurance that the benefits of such efficiency would cause the market prices to rise to a sufficient level to offset the expense of developing and implementing a common auction platform. EGSI added that ERCOT sellers may have different needs than non-ERCOT sellers in order to coordinate and schedule within ERCOT. This situation should not result in non-ERCOT sellers being forced to incur additional costs for a new common platform that includes features not applicable to non-ERCOT sellers. EGSI contended that the two existing auction platforms have proven workable and based on input from interested stakeholders, there does not appear to be a strong interest in, or need for revision of, the two existing auction platforms.

Entergy REPs were concerned that requiring PGCs to use a common platform at this time may in fact prove to be disruptive and undermine any perceived benefits. Entergy REPs noted that the PGCs currently participating in the auctions as required by PURA have already developed, tested, and implemented hardware and software programs used in the September 2001 auctions. To require a common auction platform now will necessarily involve additional expenditures, development, testing, and training of purchasers prior to implementation. OPUC and Cities commented that it is not apparent that a common auction platform would improve the efficiency of the auction process. Given that fully functional platforms have been independently developed and deployed by all of the auctioning PGCs, OPUC and Cities stated that it makes little sense to impose the additional, unnecessary financial burden of requiring that everyone adopt a new platform solely for the purpose of consistency.

REI pointed out that 86% of all capacity auctioned under this rule already uses a common platform. In all, 92% of all capacity auctioned is auctioned under a common platform. REI offered that there are benefits to a common platform, but was concerned that the costs of such an approach this late in the process may outweigh those benefits. REI stated that it does not support any mandate that parties be required to purchase new, duplicative software in order to meet this goal. REI also argued that parties have already spent considerable sums developing their own systems and that requiring parties to adopt a completely new platform now, one that has not been used to date, might actually result in increased overall costs to the sellers, buyers, and ultimately the retail customers. RRI explained that although it would be convenient if all auction products used the same platform, it does not believe that the commission can force a seller to use a common platform if it chooses otherwise.

TXU stated that it had spent hundreds of thousands of dollars developing its auction platform to comply with the commission rule (money for which there is no recovery) and that to now require

PGCs to expend more money in developing a common auction platform to comply with a revised rule would be patently unfair and potentially confiscatory. TXU added that there is no evidence that a common platform would have resulted in higher prices in the September 2001 capacity auctions. TXU further stated that by all accounts the prices that were achieved were in line with what most market participants would consider the market price for these products. TXU commented that there is a real possibility a common auction platform would only increase seller's expenses without a commensurate increase in auction prices, leaving sellers with decreased revenues. TXU deemed that requiring expensive and unnecessary repairs to a process that has already performed efficiently seems wasteful and unreasonable. In its own experience, TXUE offered that it bid under several auction platforms and was not at all deterred by the differences in these platforms. TXUE added that it does not believe that the use of a common auction platform would cause additional bidders to participate in the auctions or would in any way increase auction prices. As a follow-up, in reply comments, AEP pointed out that a strong consensus appears to have developed that no change is needed with regard to a common auction platform or a switching rule.

The commission concludes that a common auction platform is not needed. The combined comments of the parties indicate that the two existing auction platforms have proven workable and a change at this time may prove disruptive and reduce the benefits of the auction. Existing platforms have already been developed, tested, and implemented. Requiring a common platform would involve unnecessary additional expenditures for development, testing, and training of purchasers to implement a rule that may or may not improve the efficiency of the auction process.

The commission declines to require a common auction platform, as it is not clear that the benefits of a common platform outweigh the detriments of implementing the common platform, namely, the additional costs and disruptions in the auction process.

Question Number 4: Should the Capacity Auction include a switching rule to minimize price differences across PGCs?

Only one party (who is not a buyer or seller in the capacity auctions) filed comments in support of a switching rule. Alkera, which designs and develops auction software and processes, recommended that the commission adopt a switching rule so as to limit the risk that prices would fail to achieve market-clearing levels. Alkera stated that there is significant risk that this could happen in the upcoming auctions, yet provided no support for this conclusion. In addition, Alkera stated that the problems associated with no switching rule (wrong bidders winning the wrong products resulting in buyers and sellers being worse off and average prices being lower) may not have happened in the most recent Texas auction. RRI did not take a position on this issue but addressed some of the aspects involved if a switching rule were implemented.

The remaining parties that commented on this issue (AEP, EGSI, New Power, OPUC, Cities, REI, and TXU) generally stated that they were not opposed to the theoretical aspects of a switching rule. However, for the reasons stated below, all of these parties were united in opposing the implementation of a switching rule for the Texas capacity auctions. AEP explained that the commission must make sure that the benefits of a switching rule exceed the costs of such a rule. AEP noted that it does not believe that it is possible to accurately state how much benefit there is to such a rule. AEP added that CPL may not be auctioning after 2002, whether SWEPCO does so depends on the development of retail competition in the Southwest Power Pool (SPP) Power Region, and WTU offers only a few products in a zone where there may not be a lot of ability for bidders to switch between product offerings. Thus, AEP is very sensitive to the question of cost. AEP also commented that since the benefits of such a rule inure to the buyers, at least part of the cost of the rule should be imposed on those that obtain the benefits from the rule. AEP also explained that allocating the costs of a switching rule to buyers will give the commission better insight into the value that bidders place on a switching rule. If bidders do not support a switching rule, the commission should recognize such non-support as a signal that a switching rule needs to be carefully examined.

New Power elaborated on this idea, stating that it is their understanding that none of the parties that might benefit from a switching rule is clamoring to institute one. OPUC and Cities concluded that it must be determined whether any of the auction participants feel that auction outcomes will be significantly improved by switching and if neither buyers nor sellers feel there is a need for switching, the issue can be put to rest. REI commented that because a switching rule is potentially expensive to implement, it must have some perceived benefit before implementation is even considered. To REI's knowledge, none of the buyers or sellers in past auctions have expressed the opinion that the prices of entitlements would increase if switching were allowed.

EGSI noted that for switching to be effective, there must be multiple auctions with interchangeable products and that these two features may not exist in the non-ERCOT regions of Texas, which suggests that a switching rule may offer little, if any, benefits outside of ERCOT. EGSI suggested that buyers will not attempt to switch between ERCOT and non-ERCOT products to leverage prices among similar products because the products are not interchangeable between regions. In addition, EGSI stated that it and SWEPCO appear to be on different time lines to implement retail open access and the imposition of a switching rule before there are two sellers to switch between would be illogical. Also, if EGSI and SWEPCO join separate Regional Transmission Organizations (RTOs), then limits on the physical capability to transfer power between regions and the associated cost of transferring power may diminish the benefits of a switching rule. EGSI concluded by stating that it would be premature to incur the additional expense to develop and apply a switching rule that might offer little, or no, practical value to buyers and sellers in the non-ERCOT region of East Texas.

TXU commented that it could not be sure that the potential benefits of a switching rule would outweigh the certain costs of developing and implementing a switching rule. In addition, TXU noted due process concerns if the commission requires the implementation of a switching rule. TXU also proposed that the rule be republished so that parties are provided notice and a reasonable opportunity to be heard, if a switching rule is to be adopted. TXU explained that there were price differentials among PGCs in the September 2001 capacity auction, but those price differentials were appropriate price differentials. At the time of the auction, REI's baseload and gas-cyclic products were simply not perfect substitutes for TXU baseload and gas-cyclic products in the south 2001 congestion zone. The bidders knew that the delivery point for TXU's baseload and gas-cyclic products would be moving into the north 2002 congestion zone under ERCOT's planned zonal changes for 2002. The price differentials that were experienced for these products were at least partly a result of bidders valuing capacity in the north 2002 congestion zone more than they valued capacity in the south 2002 congestion zone. TXU then noted that a switching rule would not have changed this fact and would not necessarily have changed the price differentials. In addition, TXU noted that two of the largest buyers in the capacity auctions (TXU and REI) would be limited in their use of a switching rule due to affiliate relationships (an affiliate of a capacity auction seller may not purchase entitlements from that seller). TXU argued that Dr. David Salant (of Alkera), has said that there is no guarantee that the addition of a switching rule will increase Texas capacity auction revenue; thus requiring sellers to spend hundreds of thousands more to modify their capacity auction systems to comply with a revision that may not increase auction revenue is unreasonable.

In reply comments, AEP stressed the importance that after examining a switching rule, the only commenter that has voiced unqualified support for a switching rule has the most to gain from its implementation by offering to supply software to solve the "problem" it has identified. AEP contended that Alkera's comments are long on speculation and significantly short of explicit proof of its conclusions. AEP noted that this is highlighted by the remarkable conclusion of Alkera that "a few additional bids being facilitated by switching are worth tens of millions of dollars to the sellers". AEP then stated that if Alkera had proof of that contention, every seller would be demanding a switching rule. Unfortunately, such proof does not exist, and AEP is skeptical that any such proof could exist. OPUC and Cities offered in reply comments that if Alkera's assertions are correct, there could be enormous implications for the final determination of stranded costs and that sellers could conceivably oppose a switching rule as a means to keep auction prices low, with the intentions of recovering the potential price differential as stranded costs. TXU's reply comments added that Alkera has failed to acknowledge that the price disparities that were experienced between various sellers' products in the September 2001 capacity auction may very well be explained by several factors, including the different strike prices and congestion zones in the auction, and the anticipation of changing ERCOT congestion zones in 2002.

The commission finds the comments filed by the parties regarding a switching rule not to be persuasive. Therefore, the commission believes that the public interest requires a switching rule to minimize price distortions. The commission believes that the price disparities in the September 2001 and March 2002 Capacity Auctions cannot be explained solely by the differing strike prices and different congestion zones, but are based, in part, on the lack of appropriate switching provisions in the current auction design. The commission finds that the inability of bidders to switch during the auction from one affiliated PGC's products to a similar or identical product of another affiliated PGC whose price is lower, reduces the expected revenues from the auctions, and did so in the recently concluded March 2002 auction. The commission believes that the affiliated PGCs within ERCOT should implement switching procedures to reduce the risk of such price disparities in future Capacity Auctions. The affiliated PGCs within ERCOT shall provide the commission with proposed switching procedures, including detailed activity rules, for implementation in the September 2002 auction.

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. To the extent that reply comments did not significantly add to or change a party's original arguments, those reply comments are not summarized here.

Alkera's comments focused solely on a switching rule and included a description of a switching rule, the elements it would include, and how a switching rule would work. Those comments are outside the scope of the preamble questions and thus are not summarized in detail here. In addition, SPS did not specifically comment on the preamble questions, but pointed out that under PURA Chapter 30, Subchapter I, competition in SPS's service territory will be delayed until at least January 1, 2007.

REI filed reply comments concerning how to alleviate potential congestion cost problems. These comments were filed late and address new issues outside the scope of the published proposed rule and are therefore not addressed or summarized in this preamble.

Comments on specific sections of the rule:

Subsection (c)(6) Definitions:

AEP recommended that the use of "local Austin, Texas time" may be confusing to bidders outside of the state of Texas and that the use of "central prevailing time" would be more effective.

The commission agrees that referencing Austin, Texas may be confusing. This language has been changed to refer to "central prevailing time."

Subsection (d) General requirements:

AEP recommended that specific language be adopted to allow non-ERCOT and non-stranded cost companies the flexibility to alter their auction products and mechanics as discussed in Preamble Question 2.

As discussed above in connection with Preamble Question 2, AEP's recommended language is not adopted.

Subsection (e)(1) Available entitlements and amounts:

AEP recommended deleting the detailed descriptions of the products contained in subsections (f) and (g).

The commission declines to adopt the recommendation of AEP. The detailed product descriptions which AEP feels are unnecessary are included in the rule language to specify the product descriptions, instead of allowing the possibility for the offered products to change from auction to auction and seller to seller. This standardization will facilitate efficiency in the capacity auctions and liquidity in the secondary market as auction entitlements will be more easily traded.

Subsection (e)(2)(B) Forced outages:

AEP stated that the use of the word "firmness" is not entirely accurate in the context of the rule and that "availability" would more accurately express the commission's intent. RRI commented that proposed subsection (e)(2)(B) should apply only to those sellers operating two or fewer generating units in total. Sellers operating fleets of generation in multiple congestion zones should not be allowed to bypass the current rule's reliability standard because they have one or two generating units in a particular zone and the remainder of the fleet in another. REI proposed clarification that only one of the units associated with an entitlement product must be down in order to trigger the forced outage reduction.

In reply comments, AEP commented that REI's comments accurately capture the intent of the parties and if adopted, AEP's proposal would not be necessary. AEP clarified its support for REI's proposal and its opposition of RRI's proposal by stating, for example, that WTU's baseload entitlement is supported by a single plant. If that plant were to experience a forced outage, it is true that other WTU resources would continue to produce electrons, but this replacement energy would be a product at a significantly higher cost than the fuel cost mandated for the baseload product under this rule. Also, this would give the entitlement holder an availability factor greater than the underlying units, at a lower cost than that incurred by the owners of the plant. EGSI agreed with the proposed change of REI and stated that RRI's proposal is inconsistent with PURA. OPUC and Cities supported the proposal of RRI and were concerned that the forced outage rate could easily be gamed to the detriment of the entitlement holder.

The commission agrees with REI's proposed language to clarify the intent of the provision on forced outage reduction and has modified the rule accordingly. The commission does not agree with the arguments of OPUC and Cities in support of RRI's proposed interpretation. The commission finds the reply comments of AEP persuasive in illustrating that RRI's interpretation would give the entitlement holder an availability factor greater than the underlying units, at a lower cost than the actual owners of the plant. This was not the intent of the rule and the commission declines to adopt RRI's interpretation of the forced outage reduction provision.

Subsection (e)(2)(C) Forced outage notification:

AEP recommended that, for clarification purposes, the hour-ahead schedule is the appropriate time frame for determining the existence of emergency conditions and would allow the buyer the opportunity to adjust its scheduling.

The commission agrees and has modified the appropriate language in the rule.

Subsection (e)(3) Planned outage:

AEP recommended that the rule be modified to include Planned Outage Hours and Maintenance Outage Hours to determine the reductions that should be applied to the number of entitlements offered by the affiliated PGCs. Accordingly, AEP suggested that proposed subsection (e)(3) be deleted and offered substitute language. RRI recommended language that shifts entitlement adjustments for planned outages to non-shoulder months and ensures that the 15% requirement for the capacity auction is met. REI recommended clarifying language to the rule.

In reply comments, AEP stated that it believes its language proposal is best, but believes that REI's proposal is easier to understand than the proposed rule. AEP stated that it did not understand the language proposed by RRI. EGSI opposed the language of RRI and stated that the capacity auction is intended to provide bidders with a "slice" of the seller's owned generation. That owned capacity will be subject to planned maintenance to ensure the continued reliable and efficient operation of generating units. The proposed rule provides a reasonable schedule for planned maintenance and should not be revised to insulate entitlement holders from the necessity for planned maintenance. TXU echoed the opinions of EGSI, arguing that RRI's proposed change is a thinly veiled attempt to require capacity auction sellers to sell more than 15% of their capacity, in violation of PURA §39.153.

The commission finds the reply comments of AEP, EGSI, and TXU persuasive and declines to adopt the proposed language of RRI. For clarifying purposes, the proposed language of REI is adopted in lieu of AEP's proposed language.

Subsection (e)(4) Generation units offered:

AEP recommended that the language that specifies planned outage history for the years of 1998, 1999, and 2000 be modified to the most recent three operating years, as the specific years in the rule were used for the initial capacity auction when those were the most recent three operating years.

In reply comments, TXU argued that there was no reason to make AEP's proposed change. TXU noted that the planned outages for a given unit are unlikely to change significantly between the year 2000 and the end of the Texas capacity auctions. The sellers have already gathered their planned outage histories for 1998, 1999, and 2000. It does not seem cost-effective to require sellers to go through the significant expense of creating new planned outage histories when a unit's planned outages are unlikely to have changed to any great extent.

The commission agrees with the reply comments of TXU and finds that it is not cost-effective to require the calculation of new planned outage histories. It is unlikely that a unit's planned outages will change significantly. The commission declines to adopt AEP's recommended language.

Subsection (e)(5) Obligations of affiliated PGC:

AEP recommended language that would need to be included if the details of the capacity auction products were deleted from the rule and only included in the Capacity Auction EEI/NEMA Master Power Purchase & Sale Agreement.

The commission finds the recommended language of AEP inappropriate, consistent with the commission decision to retain the detailed product descriptions in the rule.

Subsection (e)(7)(A) Credit requirements:

RRI proposed that this subsection include the ratings from Fitch Investor Services and that calls for additional security should be based on a blend of the three services in lieu of the lower of the three. RRI also recommended that subsection (e)(7)(A)(ii) be amended to require posting of capacity and energy payment security no more than 90 days in advance of the month when the entitlement may be dispatched.

In reply comments, TXU argued against RRI's proposal of not posting credit until 90 days before the entitlement month. TXU argued that the capacity auction seller would have no guarantee until 90 days before dispatch that the buyer could actually pay for the entitlement.

The commission finds that the recommendation of RRI to include the ratings from Fitch Investor Services is unnecessary. The current language on credit requirements is sufficient and not significantly changed by the addition of another rating service. The commission also declines to make the recommended change proposed by RRI regarding the posting of credit. The commission finds it is inappropriate to allow potential bidders in the capacity auction the equivalent of unlimited buying credit, without any assurance of the ability to pay for awarded entitlements until after the auction and 90 days before dispatch. During this period, a buyer's financial condition could change, imperiling its ability to pay for the power. If this were to happen, the seller would be at risk for the purchase price agreed to in the auction.

Subsection (e)(7)(B)(i) Unsecured credit:

AEP recommended that the language and table be deleted and that the commission use the working group to set credit limits on an auction-by-auction basis. AEP provided substitute language to facilitate this recommendation.

The commission declines to make the change recommended by AEP. The commission believes that standardizing the credit requirements will facilitate the effectiveness of the auctions, rather than resorting to a working group to meet before each auction to negotiate new credit limits.

Subsection (e)(7)(H) Credit requirements (New language):

AEP proposed specific language to accompany its recommendation concerning Preamble Question Number 1.

Consistent with its decision in Preamble Question Number 1, the commission adopts a modified version of the language proposed by AEP regarding credit requirements.

Subsections (f) and (g) Product descriptions for capacity auctions in ERCOT and non-ERCOT areas:

AEP recommended that this section be deleted. REI proposed modifications to several portions of subsection (f) that clarify that ERCOT is the entity that dispatches ancillary services, as well as other clarifying language.

TXU disagreed with AEP in reply comments and stated that when issues have already been negotiated and agreed on for three different capacity auctions, it seems wasteful and inefficient to throw those same issues up for debate for each capacity auction. By building the product descriptions into the capacity auction rule, both capacity auction buyers and sellers will receive a measure of certainty that the dispatch systems that have already been designed will not have been designed in vain, and that the liquid wholesale market that has begun in Texas will continue. AEP recommended a slight modification to the language provided by REI, should AEP's recommendation for deletion not be adopted.

Consistent with its decision on subsection (e)(1), the commission declines to delete the detailed product descriptions in subsections (f) and (g). The commission finds the reply comments of TXU persuasive in justifying the detailed product language contained in subsections (f) and (g), and to a lesser extent in subsection (e)(1). The commission agrees that ERCOT is the entity that dispatches ancillary services and also adopts other clarifying language recommended by REI to eliminate potential confusion in subsection (f).

Subsection (f)(2)(A) Responsibility transfers:

GMEC recommended that given the preparations that the entitlement holder must make under subsection (f)(2)(B)(i), responsibility transfers (RTs) by the affiliated PGC should be completed a minimum of ten days before the commencement of the entitlement. TXU recommended a clarifying change to recognize that respective QSEs of a capacity auction seller and buyer may not have a RT agreement in place before the purchase of capacity auction products.

TXU argued against the proposal of GMEC in reply comments and stated that before a responsibility transfer can be established, essentially four parties must come together to an agreement: the buyer, the buyer's QSE, the seller, and the seller's QSE. TXU argued that it would be inappropriate and inequitable to impose the risks of an agreement not being reached on only one party to those negotiations. TXU further explained that a capacity auction seller does not have sole control of when a responsibility transfer is put into place. Under GMEC's proposal, a capacity auction buyer would have an incentive to drag its feet in reaching an agreement so that the capacity auction seller could be held liable for the financial implications if the seller failed to meet its contractual obligations.

The commission declines to adopt GMEC's changes to the proposed language. The commission finds TXU's reply arguments that it would be inappropriate to add this risk to the capacity auction seller persuasive, as it does not have sole control of when a responsibility transfer is put into place. For clarification purposes, the commission adopts the proposed language of TXU.

Subsection (f)(2)(B)(i) Notice of grouped entitlements:

TXU recommended a clarifying change to recognize that dispatch systems of some affiliated PGCs do not require the use of a written list of entitlements.

The commission adopts TXU's proposed language for clarification purposes and has made the corresponding change to the rule language.

Subsection (f)(3) – (6) Timing of scheduling for baseload, gas-intermediate, gas-cyclic, and gas-peaking:

TXU recommended language to account for possible changes in the ERCOT protocols regarding the timing of scheduling.

The commission finds it prudent to adopt TXU's recommended language to account for possible changes in ERCOT protocols concerning the timing of scheduling.

Subsection (f)(4)(A)(v) Default schedule for gas-intermediate product:

TXU recommended additional clarifying language to this subsection to account for the limitation on the number of starts for a gas-intermediate product imposed by proposed subsection (f)(4)(A)(iv)(IV).

The commission agrees with TXU that clarifying language is justified and has made corresponding changes to the rule language.

Subsection (f)(5)(A)(ii)(I) and (V) Timing of gas-cyclic scheduling:

AEP recommended that this section be deleted, but if the commission decides to keep it in the rule, AEP provided clarifying language to avoid confusion over the term "daily capacity commitment."

In reply comments, TXU stated that if the commission implements AEP's proposed language a May 2003 gas-cyclic product that was sold as a two-year strip in the September 2001 auction would be slightly different from a May 2003 gas-cyclic product sold as a one year strip in the September 2002 auction. Such differences would not only make gas-cyclic products difficult to trade, but would make it impossible to group them for dispatch.

Due to concerns over the liquidity of the wholesale market, and thus the ability to trade capacity auction products, the commission finds TXU's reply comments persuasive and declines to make AEP's recommended change.

Subsection (h) Auction process:

AEP recommended an introductory statement to clarify that non-ERCOT and non-stranded cost companies do not have to follow the auction processes described herein, if AEP's position is adopted by the commission.

Consistent with the commission's decision in Preamble Question Number 2, the commission declines to adopt AEP's recommended language.

Subsection (h)(1)(B)(iv) Auction conclusion:

TXU proposed clarifying language regarding the 15% requirement for auction conclusion. In reply comments, AEP opposed the language suggested by TXU and stated that TXU's language made the rule less clear.

The commission finds that TXU's proposed language clarifies the intent of the rule and thus adopts the recommendation.

Subsection (h)(2)(A) Auction administration:

AEP noted that if a common platform is adopted by the commission, this subsection would need to be amended accordingly.

Consistent with the commission's decision in Preamble Question Number 3, no language modification is required for subsection (h)(2)(A).

Subsection (h)(2)(B)(i) Method of notice:

AEP recommended that a better approach than administrative review would be a method where the PGC files notice and, if no protests are filed, the notice is deemed approved. AEP supplied language to this effect.

The commission agrees with AEP and finds that the proposed methodology is less administratively burdensome and thus adopts AEP's recommended language.

Subsection (h)(2)(B)(ii) Contents of notice:

TXU recommended clarifying language to illustrate that it is no longer necessary for an affiliated PGC to include a bid increment formula in its capacity auction notice because proposed subsection (h)(2)(B)(ii)(I) specifies standard bid increment ranges for all capacity auction sellers.

The commission agrees with TXU that the standard bid increment ranges replace the bid increment formula and thus the notice no longer needs to include a bid increment formula. The commission adopts TXU's clarifying language. The commission also clarifies subsection (h)(2)(B)(ii)(II) that for an entitlement subject to the forced outage provision in subsection (e)(2)(B), the most recent three-year rolling average of the forced outage rate will be included in the notice of capacity available for auction, when the designation of which power generation units will be used to meet the entitlement to be auctioned is made.

Subsection (h)(2)(B)(iii)-(v) Timing of capacity auction document submittal for notice:

TXU recommended changes necessary to ensure that capacity auction sellers will have sufficient time to review the creditworthiness of perspective bidders. In addition, these changes will ensure that approved bidders have sufficient time to review the amount of credit that has been granted and to return in executed form the applicable capacity auction-specific master agreement.

The commission finds TXU's recommended language prudent in that it will allow all parties sufficient time to review credit issues. The commission adopts TXU's recommended language.

Subsection (h)(2)(B)(v) Credit adjustment:

AEP recommended that the language that disallows additional credit after an auction begins be deleted and that new language allowing the practice be adopted.

The commission declines to adopt AEP's recommendation. While the commission recognizes that there may be benefits associated with allowing bidders to request and receive additional credit after an auction begins, the commission sees numerous problems associated with implementing such a subjective provision in a fair and non-discriminating fashion. No change has been made to the language of the proposed rule.

Subsection (h)(3)(B)(vi) Subsequent auctions:

TXU proposed a clarification concerning the start date of the September 2003 capacity auction, which was supported by EGSI in reply comments.

The commission agrees with TXU and EGSI that the start date in the rule needs to be clarified and modifies the rule accordingly.

Subsection (h)(7) Establishment of opening bid price:

RRI suggested that subsection (h)(7)(A) be amended to require sellers to issue opening bids prior to each auction subject to the challenge provisions in the proposed rule, as opening bids may be arbitrarily high, based upon outdated calculations. RRI explained that contingent on its recommendation for subsection (h)(7)(A), (h)(7)(B) would no longer be needed and recommended its deletion. REI proposed language to subsection (h)(7)(B) to clarify that the comparison of the weighted average opening bid must be completed for all entitlements of a given product across all congestion zones, and recommended that for clarification purposes, the terms "owner" and "purchaser" be replaced with "holder" throughout the rule. RRI commented that subsection (h)(7)(C) should be amended such that a seller would be deemed to have met the 15% requirement if the unsold entitlements are made available to the market through other auction mechanisms. TXU recommended clarifying language to subsection (h)(7)(C) regarding the meeting of the 15% requirement.

In reply comments, TXU was against the proposal of RRI regarding opening bids and stated that RRI seems to misunderstand the genesis of the opening bid prices in Texas. TXU stated that the capacity auction opening bid prices are cost-based and not market-based. TXU commented that contrary to RRI's assertion, market forces do not and will not change the seller's variable cost for operating its capacity. As a result, even though the market for capacity may change from auction to auction, there is no need to require auction sellers to change the opening bid prices from auction to auction. TXU also opposed RRI's proposal concerning the 15% requirement. TXU offered that the Texas capacity auctions are monitored and sanctioned by the commission to protect both capacity auction buyers and Texas consumers. A separately conducted capacity auction would not have such protections. Moreover, allowing a separately conducted capacity auction to satisfy the 15% requirement would essentially defeat the purpose of the Texas capacity auctions. EGSI also commented against RRI's proposal concerning opening bids and stated that the most volatile variable cost associated with plant operations is the cost of fuel for gas-fired generation, which is not included in the bid price. EGSI also disagreed with RRI's proposal regarding the 15% requirement. EGSI stated that the proposed rule provides sufficient commission oversight through the requirement that an affiliated PGC make a proposal to the commission through the auction notice to satisfy the 15% requirement if there is an auction where no month awards all of the entitlement of a particular product. EGSI supported REI's proposed language change regarding the use of the word "holder."

The commission declines to make RRI's recommended changes. The commission finds the reply comments of TXU and EGSI persuasive on these issues. The commission does, however, adopt the recommended clarifying language changes proposed by REI and TXU. The commission finds the proposed language consistent with the intent of the rule.

Subsection (j)(2) True-up process:

EGSI noted that the proposed rule does not incorporate the settlement of stranded cost issues in EGSI's Unbundled Cost of Service (UCOS) case and could be misinterpreted as requiring EGSI to participate in a true-up process that the commission has found to be inapplicable to EGSI. EGSI proposed language to clarify that it is not subject to the capacity auction true-up.

The commission agrees with EGSI and for clarifying purposes adopts modified language which is more general in nature, but consistent with the concerns of EGSI.

Subsection (m) Contract terms:

AEP recommended the restoration of a sentence addressing a standard agreement, contingent on its recommendation that the detailed contract language is deleted from the rule. In addition, AEP noted that Paragraph F of Schedule CA, concerning alternative dispute resolution, should be included in subsection (m) and supplied such language. TXU recommended that this section be revised to remove the references to bilateral credit requirements. GMEC's proposed language stated that failure to supply the purchased generation will result in the assessed charges being the PGC's responsibility and not the entitlement holder's.

In reply comments, TXU again opposed the bilateral credit provision and added that the capacity auction products are essentially 98% firm products backed by multiple generation units. The odds of a capacity auction seller being physically unable to meet its capacity auction obligations are extremely low. Even a catastrophic credit event for a capacity auction seller would have no effect on the seller's ability to deliver the output from its assets. This fact alone illustrates why bilateral credit terms are not necessary. TXU also offered that bilateral credit terms would be extremely difficult to implement and would be potentially financially destructive to capacity auction sellers. It would be difficult to quantify the amount of collateral that a seller would need to post in order to assure its obligations. TXU did not oppose the language recommended by GMEC as TXU felt it confirmed the buyer's rights. However TXU felt that this issue would be more appropriately dealt with in the contract and not in the Substantive Rules. Therefore, TXU offered clarifying language. Coral, Dynegy, and Tenaska supported GMEC's proposed language and stated that they believe that the language will protect buyers from ERCOT fees assessed due to short-term delivery failures by capacity auction sellers. However, they also asserted that the bilateral credit protections are necessary to protect buyers from long-term risks associated with a seller's default.

Consistent with its decision not to delete the detailed product language in subsections (f) and (g), the commission declines to adopt AEP's recommendation to restore a sentence addressing a standard agreement. The commission agrees with AEP that language concerning alternative dispute resolution should be included in subsection (m) and adopts AEP's proposed language. The commission finds TXU's reply comments persuasive and has removed the references to bilateral credit requirements. While the commission is sympathetic to the plight of buyers regarding the risk of a seller's default, the commission declines to impose the additional cost associated with meeting bilateral credit requirements on the capacity auction sellers. The commission agrees with TXU that the probability of a seller being unable to meet its contractual obligation is extremely low and therefore imposing the additional cost of a surety or performance bond, or some other form of guarantee, would not be justified. The commission finds that capacity auction products are generally 98% firm and backed by multiple generation units. The commission agrees with TXU's statement that even a catastrophic credit event is unlikely to have a long-run effect on the seller's ability to deliver the output from its assets. The commission finds that the long-run risk of these assets being unable to deliver power is not great enough to justify the cost to sellers and the potential problems associated with implementation of bilateral credit. The commission does recognize that there is a slightly greater risk associated with entitlements that are supported by a smaller number of generating units. The commission still finds this amount of risk not great enough to require bilateral credit requirements. The commission encourages participation in the Texas capacity auctions, and in an effort to eliminate as much risk as possible, the commission adopts GMEC's proposal that failure to supply the purchased generation will result in the seller's liability for any charges assessed against the entitlement holder. The commission adopts this recommendation with TXU's proposed change that clarifies that this is a contractual issue. Language reflecting these decisions has been incorporated into the rule.

Subsection (m)(4) Scheduling discrepancies:

AEP recommended that this provision be deleted from the rule as it is handled by Schedule CA. TXU recommended clarifying language that details the relationship between the general requirements of subsection (m)(4) and the more specific requirements of proposed subsection (f)(3)(A)(iv)(V) and (f)(4)(A)(v).

The commission does not agree with AEP that the language in subsection (m)(4) needs to be deleted. No persuasive argument was made that the current language needs to be deleted. For clarification purposes, the commission adopts TXU's proposed language.

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 amendment is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2002) (PURA) which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction. The commission also proposes this rule pursuant to PURA §39.153, which grants the commission authority to establish rules that define the scope of the capacity entitlements to be auctioned, and the procedures for the auctions.

Cross Reference to Statutes: Public Utility Regulatory Act §§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 the Public Utility Regulatory Act (PURA) §39.102(c) until the end of the utility's rate freeze. It is recognized that certain commission orders issued during 2001 have effectively delayed competition in the service territories of Southwestern Electric Power Company (SWEPCO) and Entergy Gulf States, Inc. (EGSI). This section shall apply to auctions conducted after 2001 by SWEPCO and/or EGSI only when competition is implemented in their respective service territories.

(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) —** Any affiliated power generation company that is unbundled from the electric utility in accordance with PURA §39.051.

(2) **Assigned units** — The PGC-specific generating units that form the block of capacity from which an entitlement is sold.

(3) **Auction start date —** The date on which an auction begins.

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

(5) **Capacity auction product** — One of the following: "baseload", "gas-intermediate", "gas-cyclic", or "gas-peaking". Each capacity auction product is further described in subsections (f) and (g) of this section.

(6) **Close of business** — 5:00 p.m., central prevailing time.

(7) **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.

(8) **Credit rating** — A credit rating on an entity's senior unsecured debt, the entity's corporate credit rating, or the entity's issuer rating.

(9) **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. For EGSI gas entitlements in the eastern congestion zone, the daily gas price will utilize the "Gas Daily" index posting for

Henry Hub. For EGSI gas entitlements in the western congestion zone, the daily gas price will be an average of the "Gas Daily" index posting for East-Houston-Katy, Houston Ship Channel.

(10) **Day-ahead** — The day preceding the operating day.

(11) **Entitlement or capacity entitlement** — The right to purchase and receive, under the applicable capacity auction master agreement, a block of 25 megawatts (MW) of electrical capacity and energy from the assigned units for a specific capacity auction product for one calendar month.

(12) **Forced outage** — An unplanned component failure or other condition that requires the unit be removed from service before the end of the next weekend.

(13) **Holder** — A person or entity that has acquired ownership of an entitlement under the terms of the applicable capacity auction Master Agreement.

(14) **Installed generation capacity** — All potentially marketable electric generation capacity owned by an affiliated PGC, 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.

(15) **Master Agreement or Agreement** — The applicable Capacity Auction EEI/NEMA Master Power Purchase & Sale Agreement.

(16) **Starts —** Direction by the holder of an entitlement to dispatch a previously idle entitlement.

(17) **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 (h) 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 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 products, defined separately in subsection (f) of this section for Electric Reliability Council of Texas,

Inc. (ERCOT) and in subsection (g) of this section for non-ERCOT areas, shall be auctioned as capacity entitlements under subsection (d) of this section. 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 section, including unit-specific capacity. Each affiliated PGC shall auction an amount of each applicable 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.

(2) **Forced outages.** For any given congestion zone:

(A) For all entitlements except those described in subparagraph (B) of this paragraph, 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 in capacity of the 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.

(B) For entitlements that are supported by two or fewer generating units, if one or more of the units providing capacity to an entitlement product experiences a forced outage or an emergency condition that 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 in capacity of the units assigned to that entitlement; provided that such reductions in availability of any single entitlement do not exceed the most recent three-year rolling average of the forced outage rate for the unit(s) supporting the entitlement. The three-year rolling average of the forced outage rate applicable to entitlements under this subparagraph shall be included in the notice of capacity available for auction, under subsection (h)(2)(B)(ii)(II) of this section.

(C) Notification of any such reductions will take place as soon as possible, but in any event, at least one hour prior to the hour-ahead scheduling period applicable to when the reduction is to take place.

(3) **Planned outage.** The total MW reduction for planned outages is determined by calculating the average MW of monthly planned outage for the generating plants associated with a product over the previous three calendar years, multiplied by 12. The resulting planned outage hours are then rounded down to the nearest whole

entitlement (25 MW block). These "outage entitlements" can then be removed from any of the five specified outage months (March, April, May, October, and November) in any combination.

(4) **Generation units offered**. If an affiliated PGC changes the assignment of a power generation unit to one of the four available product entitlements (baseload, gas-intermediate, gas-cyclic, or gas-peaking), then the affiliated PGC shall file with the commission the proposed changes in its assignment of each of its power generation units to one of the four available product entitlements 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 affiliated PGC's proposed changed assignments. If no comments are received, the affiliated PGC's proposed assignment shall be deemed appropriate. If any party objects to the affiliated PGC's proposed assignments, then the commission shall determine the appropriate assignment considering the manner in which the affiliated PGC expects to use such generation units.

(5) **Obligations of affiliated PGC**. The affiliated PGC shall dispatch entitlements only as directed by the holder of the entitlement in accordance with the applicable product description. 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 by the applicable Master Agreement, or unless 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 (h)(2)(B) of this section the point on the transmission system where energy from each entitlement is delivered to the entitlement holder.

(6) **Entitlement holder receives no possessory interest or obligations.**

(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 entitlement holder shall have the right to designate the dispatch of the entitlement, subject to other provisions of this subsection and the scheduling limitations provided for in the applicable Agreement.

(7) **Credit requirements.**

(A) Standards. Entities submitting bids and all entitlement holders shall 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 capacity price for the shorter of the duration of the entitlement or three months 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 assumed dispatch provided in either subsection (h)(6)(A)(iii) or subsection (h)(6)(C)(vi) of this section;

(iii) The entity provides a letter of credit or surety bond equal to the capacity price for the shorter of the duration of the entitlement or three months 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 assumed dispatch provided in either subsection (h)(6)(A)(iii) or subsection (h)(6)(C)(vi) of this section, 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.

(B) Unsecured credit. To be eligible for unsecured credit, entities submitting bids shall satisfy the criteria in either clause (i), (ii), or (iii) of this subparagraph, with the amount of unsecured credit to be provided to such entities to be determined as follows:

(i) For bidders with an investment grade credit rating. The amount of credit available to a bidder relying on an investment grade credit rating of itself or its guarantor will be determined according to procedures set out below. If the bidding entity or its guarantor has an investment grade credit rating and minimum equity of $100 million, the amount of credit available will be determined using the lesser of $125 million, or the applicable percentage of the bidder's stockholder equity set out in the following table, except that the amount of credit will be reduced to the extent appropriate to take into account any outstanding commitments that a bidder has for existing capacity auction entitlements.

Credit Rating (if split ratings, use lower rating)		**% of stockholder equity**
S&P	Moody's	
AAA	Aaa2	3.00%
AAA-	Aaa3	3.00%
AA+	Aa1	2.95%
AA	Aa2	2.85%
AA-	Aa3	2.70%
A+	A1	2.55%
A	A2	2.35%
A-	A3	2.10%
BBB+	Baa1	1.80%
BBB	Baa2	1.40%
BBB-	Baa3	0.70%
Below BBB-	Below Baa3	Must use another form of security

(ii) If the bidder is a municipality or cooperative not publicly rated. If the bidder is a municipality or electric cooperative that is not publicly rated but has a minimum equity (patronage capital) of $25 million, a minimum times-interest-earned ratio (TIER) of 1.05, a minimum debt service coverage (DSC) ratio of 1.00, and a minimum equity-to-assets ratio of 0.15, then the amount of credit will be the lesser of $125 million or 5.0% of the bidder's unencumbered assets, except that the amount of credit will be reduced to the extent appropriate to take into account any outstanding commitments that a bidder has for existing capacity auction entitlements.

(iii) If the bidder is a privately-held entity not publicly rated. If the bidder is a privately-held entity that is not publicly rated, but has a minimum equity of $100 million, a minimum tangible net worth of $100 million, a minimum current ratio of 1.0, a maximum debt-to-capital ratio of 0.60, and a minimum ratio of earnings before interest, taxes, depreciation, and amortization (EBITDA) to interest and current maturities of long term debt (CMLTD) of 2.0, then the amount of credit will be the lesser of $125 million or 1.80% of the bidder's stockholder equity, except that the amount of credit will be reduced to the extent appropriate to take into account any outstanding commitments that a bidder has for existing capacity auction entitlements.

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

(D) If a bidder or entitlement holder chooses to use a surety bond to satisfy its credit requirements, then the form of such surety bond will be negotiated in good faith between the bidder or entitlement holder and the affiliated PGC and reasonably acceptable by an issuer of surety bonds.

(E) 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 shall provide alternative financial evidence within three business days.

(F) The holder of the entitlement shall notify the affiliated PGC of any material changes that impact its compliance with the financial requirements it relied on in meeting the credit standards in this section.

(G) In the event the holder or seller of the entitlement fails to meet or continue to meet its security requirement, or an Event of Default results in the termination of the Agreement, 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 (h)(2)(B) of this section.

(H) If an entitlement holder's creditworthiness or financial security materially and adversely changes after the auction is completed, as a result of an event specified in the Agreement, the affiliated PGC shall provide the entitlement holder with written notice requesting additional credit support or performance assurance in a commercially reasonable manner, as set forth in the Agreement. The seller's credit requirements shall clearly identify objective criteria that would trigger a request for additional security and the methods and time frame in which an entitlement holder must satisfy such a request. The affiliated PGC may suspend delivery of any capacity or energy for which the affiliated PGC has not already received payment until the performance assurance is received, in accordance with the Agreement.

(I) If at any time after the auction is completed, there shall occur a downgrade event with respect to the credit standing of the seller, then the entitlement holder may require the seller to provide a credit assurance in an amount determined by the entitlement holder in a commercially reasonable manner. In the event the seller fails to provide a commercially reasonable performance assurance or guarantee within three business days of the receipt of notice, then an event of default shall be deemed to have occurred, and the entitlement holder will be entitled to suspend performance under the Agreement and withhold payments for energy not yet delivered, and may ultimately terminate the Agreement after the suspension period as prescribed in the Agreement.

(f) **Product descriptions for capacity auctions in ERCOT**. The provisions in this subsection apply to capacity auctions in ERCOT. Subsection (g) of this section contains provisions applicable to capacity auctions in non-ERCOT areas.

(1) **Definitions.**

(A) The following words and terms, when used in this subsection shall have the following meanings, unless the context indicates otherwise.

(i) Balancing energy service down deployed — The number of megawatt-hours (MWh) of balancing energy service down deployed by ERCOT from an entitlement.

(ii) Balancing energy service up deployed — The number of MWh of balancing energy service up deployed by ERCOT from an entitlement.

(iii) Daily capacity commitment — The amount of capacity scheduled by an entitlement holder that an affiliated PGC must make available from an entitlement for the provision of energy or permitted ancillary services for an operating day from an entitlement.

(iv) Day-ahead schedule — A schedule submitted by an entitlement holder to an affiliated PGC of the entitlement holder's scheduled usage of the entitlement for the following operating day.

(v) Default qualifying scheduling entity (QSE) — The QSE that is designated by the entitlement holder to ERCOT as its default QSE.

(vi) Energy scheduled — The final schedule for energy, for each settlement interval, that an entitlement holder submits to an affiliated PGC, subject to the limits on timing and amounts of schedules contained in the capacity auction product descriptions.

(vii) Energy deployed down — The sum of regulation energy down energy deployed and balancing energy service down energy deployed.

(viii) Energy deployed up — The sum of regulation energy up energy deployed, responsive energy deployed, non-spinning energy deployed, and balancing energy service up energy deployed.

(ix) Grouped entitlements — All of the entitlements from an affiliated PGC that an entitlement holder holds for a particular entitlement month.

(x) Grouped ancillary services — The amount of each type of ancillary service available from each entitlement grouped by:

(I) Type of ancillary service;

(II) Type of capacity auction product; and

(III) Congestion zone for those ancillary services that are, or may be, dispatched by congestion zone.

(xi) Hour-ahead schedule — A schedule other than a day-ahead schedule submitted by an entitlement holder to an affiliated PGC no later than one hour before the end of an adjustment period of the entitlement holder's scheduled use of the entitlement for the operating hour corresponding to that adjustment period.

(xii) Non-spinning energy deployed — Energy deployed by ERCOT from the non-spinning reserve service as determined under the procedures in paragraph (2)(B) of this subsection.

(xiii) Product — Electric capacity, energy, capacity auction products or other product(s) related thereto as specified in a transaction by reference to a product listed in the Agreement or as otherwise specified by the parties in a transaction.

(xiv) Regulation energy down deployed — Energy deployed down by ERCOT from the regulation energy service as determined under the procedures of paragraph (2)(B) of this subsection.

(xv) Regulation energy up deployed — Energy deployed up by ERCOT from the regulation service as determined under the procedures of paragraph (2)(B) of this subsection.

(xvi) Responsive energy deployed — Energy deployed by ERCOT from the responsive reserve service as determined under the procedures of paragraph (2)(B) of this subsection.

(xvii) Two-day-ahead schedule — A schedule submitted by the entitlement holder to the affiliated PGC of the entitlement holder's scheduled usage of the entitlement for the operating day two days in the future.

(B) The following terms have the respective meanings given to them in the ERCOT protocols as amended from time to time:

(i) Ancillary services;

(ii) Balancing energy service;

(iii) Congestion zone;

(iv) Non-spinning reserve service;

(v) Operating day;

(vi) Operating hour;

(vii) Regulation service;

(viii) Responsive reserve service;

(ix) Settlement interval; and

(x) Zonal market clearing price.

(2) **General provisions.**

(A) Responsibility transfers.

(i) The entitlement holder may not use an entitlement for the provision of balancing energy service until a responsibility transfer (RT) between the entitlement holder's QSE and the affiliated PGC's QSE is established and operated in accordance with the ERCOT protocols for the deployment of balancing energy service. The entitlement holder shall establish a separate RT with the affiliated PGC for each congestion zone from which the entitlement holder desires to provide balancing energy service.

(ii) When ERCOT has developed the details and specifications of RTs between QSEs, including without limitation, mechanics, settlement, and communication, then, at the request of the entitlement holder, the parties shall negotiate in good faith to transfer responsibility between their respective QSEs to:

(I) Allow the entitlement holder to provide balancing energy service from the entitlement; and

(II) Allocate the cost of establishing that capability.

(iii) The entitlement holder's QSE shall act as the controller of RTs used for balancing energy service from an entitlement. The entitlement holder's QSE shall use RTs to provide instructions regarding balancing energy service to the affiliated PGC's QSE. These instructions shall comply with all the limitations in the applicable capacity auction product description.

(iv) Both the entitlement holder's QSE and the affiliated PGC's QSE shall enter an inter-QSE trade in accordance with the ERCOT protocols to represent an RT before any operating hour in which the entitlement holder deploys balancing energy service from an entitlement.

(v) The affiliated PGC's QSE is only responsible for complying with RTs sent by the entitlement holder's QSE and is not responsible for ERCOT instructions sent to the entitlement holder.

(vi) The affiliated PGC and the entitlement holder shall rely upon any integration of the RT over each settlement interval performed by

ERCOT. If ERCOT does not perform that integration, then the integration shall be performed in a manner mutually agreed to by both parties.

(vii) The entitlement holder is deemed not to have provided any balancing energy service from an entitlement if the affiliated PGC loses or does not receive the balancing energy service signal from ERCOT. The affiliated PGC will promptly notify the entitlement holder if it does not receive or loses the balancing energy service signal from ERCOT.

(B) Deployment of energy from ancillary services. Subject to the limitations and conditions set out in this subsection, and except when the affiliated PGC is excused from hierarchical dispatch by ERCOT of ancillary services under clause (i) or (v) of this subparagraph, ERCOT shall be deemed to have dispatched ancillary services from the entitlements in the entitlement group in a hierarchical order according to the requirements of this subsection. Otherwise, ancillary services shall be dispatched for each entitlement in an entitlement group independently.

(i) Notice of grouped entitlements. Not later than five days before the beginning of an entitlement month, the entitlement holder shall notify the affiliated PGC of all entitlements from the affiliated PGC that are held by the entitlement holder for that entitlement month. The list shall contain sufficient detail for the affiliated PGC to identify the entitlements held by the entitlement holder for that month, including without limitation any unique entitlement number assigned by the affiliated PGC to the entitlement and listed on the letter confirmation for the entitlement. If the affiliated PGC does not timely receive this notice, then the affiliated PGC is excused from its obligation to dispatch ancillary services on a hierarchical basis under this section.

(ii) Amount of ancillary services scheduled from entitlements.

(I) The affiliated PGC shall track the amount of each ancillary service for each operating hour and the amount of each ancillary service scheduled by the entitlement holder for each operating hour, both for individual entitlements and for each grouped entitlement.

(II) For ancillary services other than the balancing energy service, which is determined by an RT, the amount of ancillary service scheduled from each entitlement and for each grouped entitlement for an operating hour is the amount stated in the final timely schedule submitted by the entitlement holder to the affiliated PGC for that operating hour for each entitlement or the entitlement group.

(iii) Deployed ancillary services.

(I) For balancing energy service, the amount of energy that ERCOT is deemed to have deployed is determined by the integration described in subparagraph (A) of this paragraph.

(II) For all ancillary services other than balancing energy service, the affiliated PGC shall track the deployment of ancillary services from the entitlement group by each grouped ancillary service for each hour in the entitlement month, except for hours in which the affiliated PGC is excused from dispatching ancillary services on a hierarchical basis under clause (i) or (v) of this subparagraph. The total amount of each grouped ancillary service deployed in an hour shall be calculated by the product of:

(-a-) The ratio of the amount of the grouped ancillary service scheduled by the entitlement holder from its grouped entitlements to the total amount of that specific ancillary service scheduled from resources in the affiliated PGC's QSE;

(-b-) The amount of energy deployed out of that grouped ancillary service in a particular congestion zone or in ERCOT as a whole, whichever is applicable.

(III) For all ancillary services other than balancing energy service, the amount of each ancillary service that ERCOT is deemed to have deployed from each entitlement, for hours in which the affiliated PGC is excused from dispatching ancillary services on a hierarchical basis under clause (i) or (v) of this subparagraph, shall be calculated by the product of:

(-a-) The ratio of the amount of that ancillary service scheduled by the entitlement holder from the entitlement to the total amount of that specific ancillary service scheduled from resources in the affiliated PGC's QSE;

(-b-) The amount of energy deployed by ERCOT out of that ancillary service in a particular congestion zone or in ERCOT as a whole, whichever is applicable.

(iv) Hierarchical deployment of grouped ancillary services.

(I) For determination of the contract price for each entitlement in a grouped entitlement, ERCOT is deemed to have first deployed grouped ancillary services that are deployed by congestion zone pursuant to subclause (III) of this clause with the amount for each entitlement spread proportionally among the entitlement holder's entitlements of that type in that congestion zone.

(II) After deploying grouped ancillary services by congestion zone pursuant to subclause (I) of this clause, ERCOT is deemed to have deployed the remainder of each grouped ancillary service pursuant to subclause (III) of this clause, with the amount for each type of entitlement spread proportionally among the entitlement holder's entitlements of that type in ERCOT.

(III) Deployed energy shall be assigned to the entitlement holder's entitlements that scheduled those ancillary services on a hierarchical basis as follows:

(-a-) For incremental deployments:

(-1-) First: Baseload entitlements, with the highest priority given to the Baseload entitlements with the lowest energy price;

(-2-) Second: Gas-intermediate entitlements;

(-3-) Third: Gas-cyclic entitlements; and

(-4-) Fourth: Gas-peaking entitlements.

(-b-) For decremental deployments:

(-1-) First: Gas-peaking entitlements;

(-2-) Second: Gas-cyclic entitlements;

(-3-) Third: Gas-intermediate entitlements; and

(-4-) Fourth: Baseload entitlements, with the highest priority given to the Baseload entitlements with the highest energy price.

(v) Exception to dispatching on hierarchical basis. The affiliated PGC is not required to dispatch ancillary services from the entitlement group on a hierarchical basis if the affiliated PGC does not have the information necessary to dispatch ancillary services from the entitlement group in a hierarchical fashion. Necessary information includes, but is not limited to, the signal from ERCOT deploying balancing energy service or the signal from ERCOT deploying other ancillary services.

(3) Baseload product.

(A) Baseload scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The entitlement holder shall submit hour-ahead schedules for ancillary services from the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) On days that ERCOT allows QSEs to change their day-ahead or two-day-ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon.

(III) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for the non-spinning reserve ancillary services from the entitlement no later than 1:45 p.m. The entitlement holder cannot change the amount of energy scheduled in a revised schedule for the non-spinning reserve ancillary services.

(IV) No hour-ahead schedules are permitted for energy from baseload entitlements. Hour-ahead schedules are permitted for ancillary services from baseload entitlements.

(iii) Schedule content. Each schedule shall specify, for each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement and the MW of each permitted ancillary service to be scheduled from the entitlement, subject to the scheduling limits in clause (iv) of this subparagraph.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at less than 20 MW from the entitlement at any time during the month.

(II) Ancillary services. The entitlement holder may use a baseload entitlement to provide responsive reserve service at a level of one MW, and non-spinning reserve service, up to a combined total of three MW. The baseload entitlement may not be used for any other ancillary service. Non-spinning reserve service may be provided from the entitlement in 30 minutes, and responsive reserve service may be provided from the entitlement in ten minutes.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause, the rate at which the entitlement holder schedules energy in each hour generally cannot change more than plus or minus two MW. The following additional restrictions apply.

(-a-) If the entitlement holder schedules or reserves any ancillary services in an hour, then the level of energy scheduled shall be the same in each settlement interval of the hour.

(-b-) The maximum change in ancillary services scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus three MW.

(-c-) The maximum change in energy scheduled from the first settlement interval in one hour to the first settlement interval in the next hour is plus or minus two MW.

(-d-) The maximum change in energy scheduled from one settlement interval to the next is plus or minus one MW.

(IV) Starts. The entitlement holder shall schedule energy from a baseload entitlement for every settlement interval and may not direct any starts of the entitlement.

(V) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule for the applicable operating day is deemed to be 20 MW of energy and zero MW of ancillary services to be delivered to the entitlement holder's designated default QSE in every settlement interval of the applicable operating day.

(B) Contract price for baseload. The items included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment. The fuel cost owed to the affiliated PGC by the entitlement holder for the dispatched baseload power will be the average cost of coal, lignite, and nuclear fuel (in dollars per MWh), as applicable to the appropriate congestion zone in which the underlying generation units are located, based on the affiliated PGC's final excess cost over market (ECOM) model as determined pursuant to PURA §39.201. Affiliated PGCs of the 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. The energy payment from the entitlement holder to the affiliated PGC is the fuel cost in dollars per MWh for the entitlement times the greater of:

(I) The sum of the total energy scheduled from the entitlement during the entitlement month plus energy deployed up from the entitlement during the entitlement month; or

(II) An amount of MWh equal to 20 MW times the number of hours in the entitlement month.

(iii) Ancillary services payment. For baseload entitlements, the ancillary services payment to be paid by the entitlement holder to the affiliated PGC is zero.

(iv) Energy deployed up reimbursement payment. For energy deployed up, for all settlement intervals in the entitlement month, the affiliated PGC shall pay the entitlement holder the sum of the zonal market clearing price of energy (MCPE) in dollars per MWh paid by ERCOT for that settlement interval times the energy deployed up in that settlement interval.

(v) Energy deployed down reimbursement payment. For energy deployed down for all settlement intervals in the entitlement month, the entitlement holder shall pay the affiliated PGC the sum of the MCPE in dollars per MWh paid to ERCOT for that settlement interval times the energy deployed down in that settlement interval.

(C) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price to the affiliated PGC after receiving an invoice for that amount in accordance with the other terms of the applicable Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(4) **Gas-intermediate product.**

(A) Gas-intermediate scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The daily capacity commitment is determined for a gas-intermediate entitlement by the 8:00

a.m. schedule. The entitlement holder shall submit hour-ahead schedules for ancillary services for the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for energy from the entitlement no later than 10:00 a.m., subject to the limit on maximum energy in clause (iv)(I)(-b-) of this subparagraph.

(III) On days that ERCOT allows QSEs to change their day-ahead or two-day-ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon, subject to the limit on maximum energy in clause (iv)(I)(-b-) of this subparagraph.

(IV) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for ancillary services from the entitlement no later than 1:45 p.m. The entitlement holder cannot change the amount of energy scheduled in a revised schedule for ancillary services.

(V) No hour-ahead schedules are permitted for energy from gas-intermediate entitlements. Hour-ahead schedules are permitted for ancillary services from gas-intermediate entitlements.

(iii) Schedule content. Each schedule shall specify:

(I) For each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement; and

(II) For each hour, the MW scheduled to be reserved for the entitlement holder's use of each ancillary service from the entitlement. The entitlement holder shall include any MW bid (but not pricing) for the balancing energy up and balancing energy down ancillary services on the schedule.

(iv) Scheduling limits.

(I) Total. Generally, the rate at which energy is scheduled cannot change more than plus or minus six MW and the rate at which ancillary services is reserved or scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW. The restrictions in items (-a-) and (-b-) of this subclause apply.

(-a-) Minimum energy. The entitlement holder may not schedule energy at less than eight MW from the entitlement at any time during the month, unless the entitlement holder has elected the gas-intermediate Start Option, in which case the entitlement holder may reduce energy below eight MW as specified in subclause (IV)(-a-) of this clause.

(-b-) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any settlement interval.

(II) Maximum changes. Subject to the limitations specified in subclause (I) of this clause:

(-a-) Generally, the rate at which energy is scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW and the rate at which ancillary services are scheduled or reserved by the entitlement holder in each hour cannot change more than plus or minus six MW. The restrictions in items (-b-) and (-c-) apply.

(-b-) Energy. Subject to the maximum change specified in item (-a-) of this subclause:

(-1-) The maximum change in energy scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus six MW.

(-2-) Subject to the limitation in subitem (-1-) of this item, the maximum change in energy scheduled from one settlement interval to the next is plus or minus two MW.

(-c-) Ancillary services. Subject to the maximum change specified in item (-a-) of this subclause, the maximum change in ancillary services scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus six MW.

(III) Ancillary services. Subject to the limitations in subclauses (I) and (II) of this clause:

(-a-) The total MW of non-spinning reserve service, regulation service up, regulation service down, responsive reserve service, and balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed ten MW;

(-b-) Subject to the limitations in item (-a-) of this subclause, the total MW of regulation service up, regulation service down, responsive reserve service, and bids for balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed:

(-1-) Four MW if the entitlement holder schedules any two-MW changes in the levels of energy within the hour;

(-2-) Five MW if the entitlement holder schedules any one-MW, but not two-MW changes in the levels of energy within the hour; or

(-3-) Six MW if the entitlement holder does not schedule any changes in the levels of energy within the hour.

(-c-) In addition to the limitations in items (-a-) and (-b-) of this subclause, the total MW of non-spinning reserve service, regulation service up, responsive reserve service, and balancing energy service up from the entitlement in a settlement interval shall not exceed an amount of MW equal to the daily capacity commitment for the settlement interval minus the energy scheduled for that settlement interval.

(-d-) In addition to the limitations in items (-a-), (-b-), and (-c-) of this subclause, the total MW of regulation service down and balancing energy service down from the entitlement in a settlement interval shall not exceed an amount of MW equal to the energy scheduled for that settlement interval minus eight MW.

(-e-) In addition to the limitations in items (-a-), (-b-), and (-c-) of this subclause, if the energy schedule is at zero as permitted under subclause (IV)(-a-) of this clause, then the entitlement holder may not schedule any ancillary services from the gas-intermediate entitlement.

(-f-) Non-spinning reserve service may be provided from the entitlement in 30 minutes, and other permitted ancillary services may be provided from the entitlement in ten minutes.

(IV) Starts, minimum off time, and minimum run time.

(-a-) The entitlement holder may reduce the energy schedule from the gas-intermediate entitlement to zero MW two times during the entitlement month.

(-b-) Once the energy schedule is reduced to zero, it shall remain at zero for not less than 48 hours.

(-c-) If the entitlement holder increases the energy schedule from zero, then energy shall be scheduled at a minimum of eight MW, and the energy schedule may not be reduced to zero again for at least 72 hours after the energy schedule increased from zero.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule, for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, eight MW for the daily capacity commitment, eight MW of energy to be delivered to the entitlement holder's designated default QSE, and zero MW of ancillary services, and that deemed schedule may not be changed in any hour-ahead schedule. However, if the entitlement holder has used up its allowable starts for the entitlement month, then the schedule for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment.

(B) Gas-intermediate ancillary services. Subject to the scheduling limits in subparagraph (A) of this paragraph, the entitlement holder may use the entitlement in any one hour for one or more of these ancillary services:

regulation service up, regulation service down, responsive reserve service, non-spinning reserve service, balancing energy service up, and balancing energy service down. When ERCOT requires mandatory balancing energy down bids, then the affiliated PGC shall so notify the entitlement holder, and the entitlement holder shall then submit a balancing energy down bid to ERCOT in the same percentage that ERCOT requires of the affiliated PGC, subject to the MW limits for gas-intermediate in the applicable Schedule CA of the applicable Agreement.

(C) Contract price for gas-intermediate. The items included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment from the entitlement holder to the affiliated PGC for each settlement interval in the entitlement month, is the sum of the minimum energy payment and the excess energy payment.

(-a-) The minimum energy payment is the product of the number of hours in the entitlement month at which the energy level is not zero as permitted under subparagraph (A)(iv)(IV)(-a-) of this paragraph, times eight MWh, times the minimum fuel price.

(-b-) The excess energy payment for each settlement interval is the excess fuel price defined in subclause (II)(-b-) of this clause, times (energy scheduled minus two MWh plus energy deployed up minus energy deployed down).

(II) Fuel price.

(-a-) The minimum fuel price is a heat rate equal to 9.9 Million British Thermal Units (MMBtu) per MWh times the daily gas price.

(-b-) The excess fuel price is a heat rate equal to 9.9 MMBtu per MWh times the daily gas price.

(iii) Ancillary services payment.

(I) The ancillary services cost adjustment payment to be paid by the entitlement holder to the affiliated PGC is the ancillary services cost defined in subclause (II) of this clause times the difference, for each settlement interval of the entitlement, between the daily capacity commitment and energy scheduled.

(II) The ancillary services cost is a heat rate adjustment equal to 1.015 MMBtu per MW times the daily gas price.

(iv) Energy deployed up reimbursement payment. For energy deployed up for all settlement intervals in the entitlement month, the affiliated PGC shall pay the entitlement holder the MCPE in dollars per MWh paid by ERCOT for a settlement interval times the energy deployed up in a settlement interval.

(v) Energy deployed down reimbursement payment. For energy deployed down for all settlement intervals in the entitlement month, the entitlement holder shall pay the affiliated PGC the MCPE in dollars per MWh paid to ERCOT for a settlement interval times the energy deployed down in a settlement interval.

(D) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the Agreement.

(5) **Gas-cyclic.**

(A) Gas-cyclic scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules for both energy and ancillary services. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The daily capacity commitment is determined for a gas-cyclic entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies the affiliated PGC, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-cyclic start deadline defined in subclause (V) of this clause. The entitlement holder shall submit hour-ahead schedules for the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for energy from the entitlement no later than 10:00 a.m.

(III) On days that ERCOT allows QSEs to change their day-ahead or two-day ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon.

(IV) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for ancillary services from the entitlement no later than 1:45 p.m.

(V) The gas-cyclic start deadline for declaring the daily capacity commitment for each settlement interval in an operating hour is 14 hours before the end of the adjustment period for that operating hour.

(iii) Schedule content. Each schedule shall specify:

(I) For each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement; and

(II) For each hour, the MW scheduled to be reserved for the entitlement holder's use of each ancillary service from the entitlement. The entitlement holder shall include any MW bid (but not pricing) for the balancing energy up and balancing energy down ancillary services on the schedule.

(iv) Scheduling limits.

(I) Total. Generally, the rate at which energy is scheduled cannot change more than plus or minus six MW and the rate at which ancillary services is reserved or scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW. The restrictions in items (-a-) and (-b-) of this subclause apply.

(-a-) Minimum energy. The entitlement holder may not schedule energy at any level between zero MW and five MW from the entitlement at any time during the month.

(-b-) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any settlement interval after the entitlement holder designates its daily capacity commitment.

(II) Maximum changes. Subject to the limits specified in subclause (I) of this clause:

(-a-) The maximum change in the rate at which energy is scheduled from the first settlement interval in one hour to the first settlement interval in the next hour is plus or minus six MW;

(-b-) Subject to the limitation in item (-a-) of this subclause, the maximum change in the rate at which energy is scheduled from one settlement interval to the next is plus or minus two MW; and

(-c-) Subject to the limitation specified in item (-a-) of this subclause, the maximum change in ancillary services scheduled from the first settlement interval in one hour to the first settlement interval of the next hour is plus or minus six MW.

(III) Ancillary services. Subject to the limitations in subclauses (I) and (II) of this clause:

(-a-) The total MW of non-spinning reserve service, regulation service up, regulation service down, responsive reserve service, and balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed ten MW;

(-b-) Subject to the limitations in item (-a-) of this subclause, the total MW of regulation service up, regulation service down, responsive reserve service, and bids for balancing energy service up and balancing energy service down from the entitlement in one hour shall not exceed:

(-1-) Four MW if the entitlement holder schedules any two-MW changes in the levels of energy within the hour;

(-2-) Five MW if the entitlement holder schedules any one-MW, but not two-MW changes in the levels of energy within the hour; or

(-3-) Six MW if the entitlement holder does not schedule any changes in the levels of energy within the hour.

(-c-) In addition to the limitations in items (-a-) and (-b-) of this subclause, the total MW of non-spinning reserve service, regulation service up, responsive reserve service, and balancing energy service up from the entitlement in a settlement interval shall not exceed an amount of MW equal to the daily capacity commitment for the settlement interval minus the energy scheduled for that settlement interval.

(-d-) In addition to the limitations in items (-a-), (-b-), and (-c-) of this subclause, the total MW of regulation service down and balancing energy service down from the entitlement in a settlement interval shall not exceed an amount of MW equal to the energy scheduled for that settlement interval minus five MW.

(-e-) Non-spinning reserve service may be provided from the entitlement in 30 minutes, and other permitted ancillary services may be provided from the entitlement in ten minutes.

(IV) Starts. Subject to the limits specified in subclause (I) - (III) of this clause, the entitlement holder may not direct more than 20 starts during the month of the entitlement, and the entitlement holder may not direct more than one start per day. A start occurs every time a schedule increases the MW of energy from zero MW. Once 20 starts have occurred during the entitlement, the energy scheduled by the entitlement holder may not be lower than a rate of five MW unless that level is lowered to zero MW, at which time the level may not be raised above zero MW for the remainder of the entitlement.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment, zero MW of energy, and zero MW of ancillary services. This deemed schedule may not be changed in any hour-ahead schedule.

(B) Gas-cyclic ancillary services. Subject to the scheduling limits in subparagraph (A) of this paragraph, the entitlement holder may use the entitlement in any one hour for one or more of these ancillary services: regulation service up, regulation service down, responsive reserve service, non-spinning reserve service, balancing energy service up, and balancing energy service down. When ERCOT requires mandatory balancing energy service down bids, then the affiliated PGC shall so notify the entitlement holder, and the entitlement holder shall then submit a balancing energy service down bid in the same percentage that ERCOT requires of the affiliated PGC, subject to the MW limits for gas-cyclic in this paragraph.

(C) Contract price for gas-cyclic. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval from the entitlement holder to the affiliated PGC is the fuel price defined in subclause (II) of this clause times (energy scheduled plus energy deployed up minus energy deployed down.)

(II) Fuel price.

(-a-) The fuel price, for the portion of the daily capacity commitment that is designated by the entitlement holder by 8:00 a.m. in the day-ahead or two-day-ahead schedule, is a heat rate equal to 12.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price, for the portion of the daily capacity commitment that is not released or committed at 8:00 a.m., but is committed before the gas-cyclic start deadline, is a heat rate equal to 12.100 MMBtu per MWh times (the sum of the daily gas price plus $ .25.)

(iii) Ancillary services payment.

(I) The ancillary services payment to be paid by the entitlement holder to the affiliated PGC is the product of the ancillary services cost defined in subclause (II) of this clause times the difference, for each settlement interval of the entitlement, between the daily capacity commitment and energy scheduled.

(II) The ancillary services cost is a heat rate adjustment equal to 1.622 MMBtu per MW times the daily gas price.

(iv) Energy deployed up reimbursement payment. For energy deployed up, for all settlement intervals in the entitlement month, the affiliated PGC shall pay the entitlement holder the MCPE in dollars per MWh paid by ERCOT for a settlement interval times the energy deployed up in a settlement interval.

(v) Energy deployed down reimbursement payment. For energy deployed down for all settlement intervals in the entitlement month, the entitlement holder shall pay the affiliated PGC the MCPE in dollars per MWh paid to ERCOT for a settlement interval times the energy deployed down in a settlement interval.

(D) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the other terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(6) **Gas-peaking.**

(A) Gas-peaking scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules. The entitlement holder shall submit a two-day-ahead schedule for the entitlement if notified to do so by ERCOT.

(ii) Timing of scheduling. All of the times for scheduling referred to in this subparagraph are based on the times in the ERCOT protocols. If the times in the ERCOT protocols are changed, then the times in this subparagraph will be considered to have changed to equitably accommodate the changes in the ERCOT protocols.

(I) The entitlement holder shall submit day-ahead or two-day-ahead schedules for the entitlement to the affiliated PGC no later than 8:00 a.m. The daily capacity commitment is determined for a gas-peaking entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies the affiliated PGC, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-peaking start deadline defined in subclause (V) of this clause. The entitlement holder shall submit hour-ahead schedules for the entitlement to the affiliated PGC no later than one hour before the deadline for the affiliated PGC's QSE to submit hour-ahead schedules to ERCOT.

(II) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for energy from the entitlement no later than 10:00 a.m.

(III) On days that ERCOT allows QSEs to change their day-ahead or two-day ahead schedules to ERCOT by 1:00 p.m. for congestion or capacity insufficiency, the entitlement holder may submit a revised day-ahead or two-day-ahead schedule for energy from the entitlement to the affiliated PGC no later than noon.

(IV) The entitlement holder may submit to the affiliated PGC a revised day-ahead or two-day-ahead schedule for the non-spinning reserve service from the entitlement no later than 1:45 p.m.

(V) The gas-peaking start deadline for declaring the daily capacity commitment for each settlement interval in an operating hour is one hour before the end of the adjustment period for that operating hour.

(iii) Schedule content. Each schedule shall specify:

(I) For each settlement interval, the MW of energy scheduled to be delivered to the entitlement holder from the entitlement; and

(II) For each hour, the MW scheduled to be reserved for the entitlement holder's use of the non-spinning reserve service from the entitlement.

(iv) Scheduling limits.

(I) Total.

(-a-) The rate at which energy is scheduled or ancillary services reserved or scheduled by the entitlement holder in each settlement interval during an hour shall be either zero MW or 25 MW and cannot change during the hour.

(-b-) Subject to the requirement of item (-a-) of this subclause, if the entitlement holder schedules any energy from the entitlement in an hour, the rate at which energy is scheduled shall continue uninterrupted at a level of 25 MW for not less than four hours.

(-c-) Subject to the requirements of items (-a-) and (-b-) of this subclause, when the entitlement holder decreases a schedule for energy to zero MW from the entitlement in an hour, the rate at which energy is scheduled or at which ancillary services is scheduled or reserved shall continue uninterrupted at a level of zero MW for not less than two hours.

(II) Starts. The number of starts of the entitlement is not limited.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead or two-day ahead schedule, as applicable, then the schedule, for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment, zero MW of energy, and zero MW of the non-spinning reserve service. This deemed schedule may not be changed in any revised day-ahead or two-day ahead schedule, or in any hour-ahead schedule.

(B) Gas-peaking ancillary services. The entitlement holder may not use the entitlement for any ancillary service except the non-spinning reserve service.

(C) Contract price for gas-peaking. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval, from the entitlement holder to the affiliated PGC is the fuel price defined in subclause (II) of this clause times (energy scheduled plus non-spinning energy deployed plus non-spinning energy instructed deviation.)

(II) Fuel price.

(-a-) The fuel price, for operating days for which the entitlement holder designated its daily capacity commitment by 8:00 a.m. in the day-ahead or two-day ahead schedule, is a heat rate equal to 14.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price, for operating days for which the entitlement holder exercises its option to designate its daily capacity commitment after 8:00 a.m. and before the gas-peaking start deadline, is a heat rate equal to 14.100 MMBtu per MWh times the sum of the daily gas price plus $ .25.

(iii) Ancillary services payment. The ancillary services payment to be paid by the entitlement holder to the affiliated PGC is the product of $1.00 per MW times the total number of MW of non-spinning reserve service scheduled during each hour of the entitlement month.

(iv) Ancillary services reimbursement payment. The ancillary services reimbursement payment from the affiliated PGC to the entitlement holder is the sum of the MCPE for energy in dollars per MWh paid by ERCOT for each MWh of non-spinning energy deployed and the price that ERCOT pays for uninstructed deviations for each MWh of non-spinning energy uninstructed deviation.

(D) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the other terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(g) **Product descriptions for capacity in non-ERCOT areas**. The provisions in this subsection apply to capacity auctions in non-ERCOT areas. Subsection (f) of this section contains provisions applicable to capacity auctions in ERCOT.

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

(A) Daily capacity commitment — The amount of capacity scheduled by the entitlement holder that a seller shall make available for the provision of energy from an entitlement.

(B) Day ahead schedule — A schedule submitted by the entitlement holder to a seller of the entitlement holder's scheduled usage of the entitlement for the following operating day.

(C) Energy scheduled — For each settlement interval, the final schedule for energy that the entitlement holder submits to a seller, subject to the limits on timing and amounts of schedules contained in this subsection.

(D) Grouped entitlements — All of the entitlements from a seller that the entitlement holder holds for a particular entitlement month.

(E) Hour-ahead schedule — A schedule other than a day-ahead schedule submitted by the entitlement holder to a seller of the entitlement holder's scheduled usage of the entitlement for the following operating hour.

(2) **Baseload product.**

(A) Description. For each baseload capacity entitlement, the scheduled power shall be provided to the entitlement holder 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 subparagraph (E) of this paragraph.

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

(C) Fuel price. The fuel cost owed to the affiliated PGC by the entitlement holder 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 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.

(D) Starts per month. The entitlement holder of a baseload capacity entitlement shall 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 of baseload capacity entitlements.

(E) Baseload scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to the seller no later than 8:00 a.m. The daily capacity commitment is determined for a baseload entitlement by the 8:00 a.m. schedule.

(II) The entitlement holder may submit to the seller a revised day-ahead schedule for energy from the entitlement no later than noon, subject to the limit on maximum energy in clause (iv)(II) of this subparagraph.

(III) No hour-ahead schedules are permitted for energy from baseload entitlements.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, subject to the scheduling limits in clause (iv) of this subparagraph, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at less than 20 MW from the entitlement at any time during the month.

(II) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any scheduling interval.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause:

(-a-) Total. Generally, the rate at which energy is scheduled by the entitlement holder in each hour cannot change more than plus or minus two MW.

(-b-) Energy. Subject to the maximum change specified in item (-a-) of this subclause, the maximum change in energy scheduled from one scheduling interval to the next scheduling interval cannot exceed plus or minus two MW.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead schedule, as applicable, then the schedule for the applicable operating day shall be deemed to be, in every settlement interval of the applicable operating day, a total of 20 MW for the daily capacity commitment.

(F) Contract price for baseload. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment. The fuel price is as specified on the letter confirmation for the entitlement. The energy payment from the entitlement holder to the affiliated PGC is the fuel price in dollars per MWh specified in the letter confirmation for the entitlement times the greater of:

(I) The total energy scheduled from the entitlement during the entitlement month; or

(II) An amount of MWh equal to 20 MW times the number of hours in the entitlement month.

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price to the affiliated PGC after receiving an invoice for that amount in accordance with the other terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the other terms of the Agreement.

(3) **Gas-intermediate product.**

(A) Description. For each gas-intermediate capacity entitlement, not less than 30% of the entitlement shall be provided to the entitlement holder at any time when any of the entitlement is being scheduled by the entitlement holder , with the remainder of the block scheduled as day-ahead shaped power in accordance with the scheduling requirements and limitations provided in subparagraph (E) of this paragraph.

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

(C) Fuel price.

(i) Except as specified otherwise in clause (ii) of this subparagraph, the fuel cost owed to the affiliated PGC by the entitlement holder for the gas-intermediate capacity dispatched will be 10.850 MMBtu per MWh heat rate times the minimum MWh that shall be taken for gas-intermediate capacity as required in subparagraph (A) of this paragraph 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 MWh required, the additional fuel price owed to the affiliated PGC will be 10.850 MMBtu per MWh times the MWh of gas-intermediate power dispatched pursuant to the entitlement above the minimum requirement times the daily gas price.

(ii) EGSI.

(I) For EGSI gas-intermediate capacity in the eastern congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-intermediate capacity dispatched will be 10.850 MMBtu per MWh heat rate times the minimum MWh that shall be taken for gas-intermediate capacity as required in subparagraph (A) of this paragraph times the first-of-the-month index posted in the publication "Inside FERC" for Henry Hub for the month of the entitlement. For power dispatched above the minimum MWh required, the additional fuel price owed to the affiliated PGC will be 10.850 MMBtu per MWh times the MWh of gas-intermediate power dispatched pursuant to the entitlement above the minimum requirement times the Henry Hub daily gas price.

(II) For EGSI gas-intermediate capacity in the western congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-intermediate capacity dispatched will be 10.850 MMBtu per MWh heat rate times the minimum MWh that shall be taken for gas-intermediate capacity as required in subparagraph (A) of this paragraph times the average of the first-of-the-month index posted in the publication "Inside FERC" for Henry Hub for the month of the entitlement and 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 MWh required, the additional fuel price owed to the affiliated PGC will be 10.850 MMBtu per MWh times the MWh of gas-intermediate power dispatched pursuant to the entitlement above the minimum requirement times the average of the Henry Hub daily gas price and the Houston Ship Channel daily gas price.

(D) Starts per month. The entitlement holder of gas-intermediate capacity shall take a minimum of 30% of the power from the entitlement in each interval and is therefore not permitted to direct the affiliated PGC to make any starts of gas intermediate capacity entitlements.

(E) Gas-intermediate scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to the seller no later than 8:00 a.m. The daily capacity commitment is determined for a gas-intermediate entitlement by the 8:00 a.m. schedule.

(II) The entitlement holder may submit to seller a revised day-ahead schedule for energy from the entitlement no later than noon, subject to the limit on maximum energy in clause (iv)(II) of this subparagraph.

(III) No hour-ahead schedules are permitted for energy from gas-intermediate entitlements.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at less than eight MW from the entitlement at any time during the month.

(II) Maximum energy. The entitlement holder may not schedule energy at a level greater than the daily capacity commitment in any scheduling interval.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause and the maximum energy rate specified in subclause (II) of this clause, the energy scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW.

(v) Default schedule. If the entitlement holder does not submit a timely day-ahead schedule, as applicable, then the schedule for the applicable operating day shall be deemed to be, in every settlement interval of the applicable operating day, a total of eight MW for the daily capacity commitment. This deemed schedule may not be changed in any hour-ahead schedule.

(F) Contract price for gas-intermediate. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment from the entitlement holder to the affiliated PGC is the sum, for each settlement interval in the entitlement month, of the minimum energy payment and the excess energy payment.

(-a-) The minimum energy payment is the product of eight MWh times the minimum fuel price.

(-b-) The excess energy payment is the product, for each settlement interval, of the excess fuel price defined in subclause (II)(-b-) of this clause times energy scheduled.

(II) Fuel price.

(-a-) The minimum fuel price is the product of a heat rate equal to 10.850 MMBtu per MWh times the daily gas price.

(-b-) The excess fuel price is the product of a heat rate equal to 10.850 MMBtu per MWh times the daily gas price.

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the terms of the Agreement.

(4) **Gas-cyclic product.**

(A) Description. The gas-cyclic entitlement shall be flexible day-ahead shaped power.

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

(C) Fuel price.

(i) Except as specified otherwise in clause (ii) of this subparagraph, the fuel price owed to the affiliated PGC by the capacity entitlement holder for gas-cyclic capacity dispatched will be 12.100 MMBtu per MWh times the MWh of the gas-cyclic power dispatched under the entitlement times the daily gas price.

(ii) EGSI.

(I) For EGSI gas-cyclic capacity in the eastern congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-cyclic capacity dispatched will be 12.100 MMBtu per MWh times the MWh of gas-cyclic power dispatched under the entitlement times the Henry Hub daily gas price.

(II) For EGSI gas-cyclic capacity in the western congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-cyclic capacity dispatched will be 12.100 MMBtu per MWh times the MWh of gas-cyclic power dispatched under the entitlement times the average of the Henry Hub daily gas price and the Houston Ship Channel daily gas price.

(D) Starts per month and associated costs. The entitlement holder 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 pursuant to subparagraph (E)(v) of this paragraph.

(E) Gas-cyclic scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to seller no later than 8:00 a.m. The daily capacity commitment is determined for a gas-cyclic entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies seller, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-cyclic start deadline pursuant to subclause (IV) of this clause.

(II) The entitlement holder may submit to seller a revised day-ahead schedule for energy from the entitlement no later than noon, subject to the limit on maximum energy in clause (iv)(II) of this subparagraph.

(III) No hour-ahead schedules are permitted for energy from gas-cyclic entitlements.

(IV) The gas-cyclic start deadline for declaring the daily capacity commitment for each settlement interval in an operating hour is 15 hours before the start of the operating hour.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) Minimum energy. The entitlement holder may not schedule energy at any level between zero MW and five MW from the entitlement at any time during the month.

(II) Maximum energy. The entitlement holder may not schedule energy at any level greater than the daily capacity commitment in any scheduling interval.

(III) Maximum changes. Subject to the minimum energy rate specified in subclause (I) of this clause and the maximum energy rate specified in subclause (II) of this clause, the energy scheduled by the entitlement holder in each hour cannot change more than plus or minus six MW.

(v) Starts. The entitlement holder shall not direct more than 20 starts during the month of the entitlement, and the entitlement holder shall not direct more than one start per day. A start occurs every time a schedule increases the MW of energy from zero MW. Once the maximum number of starts have occurred during the entitlement, the energy scheduled by the entitlement holder may not be lower than a rate of five MW unless that level is lowered to zero MW, at which time the level may not be raised above zero MW for the remainder of the month.

(vi) Default schedule. If the entitlement holder does not submit a timely day-ahead schedule as applicable, then the schedule for the applicable operating day is deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment and zero MW of energy. This deemed schedule may not be changed.

(F) Contract price for gas-cyclic. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval from the entitlement holder to the affiliated PGC is the product, of the fuel price defined in subclause (II) of this clause times energy scheduled.

(II) Fuel price.

(-a-) The fuel price, for the portion of the daily capacity commitment that is designated by the entitlement holder by 8:00 a.m. in the day-ahead schedule, is the product of a heat rate equal to 12.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price for the portion of the daily capacity commitment that is not released or committed at 8:00 a.m., but committed before the gas-cyclic start deadline, is the product of a heat rate equal to 12.100 MMBtu per MWh times (the sum of the daily gas price plus $ 0.25.)

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the terms of the Agreement.

(5) **Gas-peaking product.**

(A) Description. The gas-peaking entitlement shall be intra-day power.

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

(C) Fuel price.

(i) Except as specified in clause (ii) of this subparagraph, the fuel price owed to the affiliated PGC by the entitlement holder for gas-peaking capacity dispatched will be 14.100 MMBtu per MWh times the MWh of the gas-peaking power dispatched under the entitlement times the daily gas price.

(ii) EGSI.

(I) For EGSI gas-peaking capacity in the eastern congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-peaking capacity dispatched will be 14.100 MMBtu per MWh times the

MWh of gas-peaking power dispatched under the entitlement times the Henry Hub daily gas price.

(II) For EGSI gas-peaking capacity in the western congestion zone, the fuel cost owed to its affiliated PGC by the capacity entitlement holder for the gas-peaking capacity dispatched will be 14.100 MMBtu per MWh times the MWh of gas-peaking power dispatched under the entitlement times the average of the Henry Hub daily gas price and the Houston Ship Channel daily gas price.

(D) Starts per month and associated costs. The entitlement holder 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) Gas-peaking scheduling.

(i) Schedule types. The entitlement holder shall submit a day-ahead schedule for the entitlement and may submit hour-ahead schedules.

(ii) Timing of scheduling.

(I) The entitlement holder shall submit day-ahead schedules for the entitlement to the seller no later than 8:00 a.m. The daily capacity commitment is determined for a gas-peaking entitlement by the 8:00 a.m. schedule, unless the entitlement holder notifies the seller, in the schedule, that it is exercising its option to set the daily capacity commitment in the last schedule submitted before the gas-peaking start deadline defined in subclause (III) of this clause. The entitlement holder shall submit hour-ahead schedules for the entitlement to the seller no later than one hour before the start of the operating hour.

(II) The entitlement holder may submit to the seller a revised day-ahead schedule for energy from the entitlement no later than noon.

(III) The gas-peaking start deadline for declaring the daily capacity commitment for each operating hour is two hours before the beginning of the operating hour.

(iii) Schedule content. Each schedule shall specify, for each scheduling interval, the energy scheduled to be delivered to the entitlement holder from the entitlement.

(iv) Scheduling limits.

(I) The rate at which energy is scheduled by the entitlement holder in each scheduling interval during one hour shall be either zero MW or 25 MW and cannot change during the hour.

(II) Subject to the requirement of subclause (I) of this clause, if the entitlement holder schedules any energy from the entitlement in one hour, the rate at which energy is scheduled shall continue uninterrupted at a level of 25 MW for not less than four hours.

(III) Subject to the requirements of subclause (I) and (II) of this clause, when the entitlement holder decreases a schedule for energy to zero MW from the entitlement in one hour, the energy scheduled shall continue uninterrupted at a level of zero MW for not less than two hours.

(v) Default Schedule. If the entitlement holder does not submit a timely day-ahead schedule then the schedule for the applicable operating day shall be deemed to be, in every settlement interval of the applicable operating day, zero MW for the daily capacity commitment and zero MW of energy. This deemed schedule may not be changed in any revised day-ahead schedule, or in any hour-ahead schedule.

(F) Contract price for gas-peaking. The items to be included in the contract price between the entitlement holder and the affiliated PGC for the entitlement shall include:

(i) Capacity payment. The capacity payment from the entitlement holder to the affiliated PGC is the capacity price in dollars per MW specified in the letter confirmation for the entitlement times 25 MW.

(ii) Energy payment.

(I) The energy payment for each settlement interval from the entitlement holder to the affiliated PGC is the product of the fuel price defined in subclause (II) of this clause times energy scheduled.

(II) Fuel price.

(-a-) The fuel price, for operating days for which the entitlement holder designated its daily capacity commitment by 8:00 a.m. in the day-ahead schedule, is the product of a heat rate equal to 14.100 MMBtu per MWh times the daily gas price.

(-b-) The fuel price, for operating days for which the entitlement holder exercised its option to designate its daily capacity commitment after 8:00 a.m. and before the gas-peaking start deadline, is the product of a heat rate equal to 14.100 MMBtu per MWh times (the sum of the daily gas price plus $ .25).

(G) Timing of payment of contract price. The entitlement holder shall pay the affiliated PGC the capacity payment portion of the contract price not less than five days before the beginning of the entitlement month or 20 days after receiving an invoice for the capacity payment from the affiliated PGC, whichever is later. The entitlement holder shall pay the remainder of the contract price after receiving an invoice for that amount in accordance with the terms of the Agreement. If the affiliated PGC owes the entitlement holder any net amount under the contract price calculation, it will pay that amount to the entitlement holder in accordance with the terms of the Agreement.

(6) **Scheduling discrepancies.** If the entitlement holder submits a schedule to seller for an entitlement that violates any of the scheduling requirements for that capacity auction product type, the schedule shall be deemed a non-conforming schedule for a scheduled hour. The schedule for that non-conforming scheduled hour shall then be deemed to be the same as the schedule for the nearest preceding hour for which the schedule was not a non-conforming schedule. The seller shall promptly notify the entitlement holder of a non-conforming schedule.

(7) **Ancillary services.** Until such time that all ancillary services issues are addressed and resolved within the context of a Federal Energy Regulatory Commission (FERC) approved regional transmission organization, entitlements will include rights only to energy and capacity as described in this subsection and specifically exclude any ancillary services rights. Such exclusion is consistent with subsection (e)(1) of this section, which allows products other than those described in this subsection to be offered with good cause. In the interim, the affiliated PGC shall provide the required ancillary services to eligible customers at the current FERC-approved rates.

(h) **Auction process.**

(1) **Timing issues.**

(A) Frequency of auctions.

(i) Auction dates. Capacity auctions shall begin on March 10, July 10, September 10, and November 10 of each year. If the date for an auction start falls on a weekend or banking holiday, then that auction shall begin on the first business day after the weekend or banking holiday.

(ii) Simultaneous auctions. Auctions for a product will be held simultaneously by all affiliated PGCs of entitlements within the respective North American Electric Reliability Council (NERC) regions in Texas. For example, ERCOT and non-ERCOT auctions can be held at different times and dates.

(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 first day after the auction closes that is not a weekend or banking holiday.

(iii) Confidentiality and posting of bids. 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 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 information on the quantity of each product requested by bidders during each round of an auction, 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.

(iv) The affiliated PGC shall be deemed to have met the 15% requirement if it offered products in a product category (for example, gas-intermediate) and successfully sold, at least, all of the entitlements offered in one particular month, in that product category. If there is no month in which all of the products in a product category are sold, the affiliated PGC shall comply with the provisions of paragraph (7)(C) of this subsection.

(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 start date, each affiliated PGC offering capacity entitlements at auction shall file with the commission notice of the pending auction. Within 20 days of the filing of the notice, interested parties may provide comments on the affiliated PGC's proposed notice. If no comments are received, the affiliated PGC's proposed notice shall be deemed appropriate. If any party objects to the affiliated PGC's proposed notice, then the commission shall administratively approve, reject, or approve the notice with modifications.

(ii) Contents of notice.

(I) The auction notice shall include the auction start 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 following range of bid increments for each product type to be used to adjust the price of entitlements between rounds of the auction:

(-a-) Baseload - $ .05 to $ .75;

(-b-) Gas-intermediate - $ .02 to $ .30;

(-c-) Gas-cyclic - $ .02 to $ .30;

(-d-) Gas-peaking - $ .02 to $ .30.

(II) 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 prescribed in subsections (f)(3)(B)(ii) and (g)(2)(F)(ii) of this section at the time of the auction. If an entitlement to be auctioned is subject to the forced outage provision in subsection (e)(2)(B) of this section, then the notice must include the applicable three-year rolling average of the forced outage rate.

(iii) The affiliated PGCs shall publish their respective notices and application forms on their web sites no later than 45 calendar days before the start of each auction. Each entity that intends to bid in an affiliated PGC's auction shall complete the forms, which include the first page of the cover sheet to the Agreement, and submit them to the affiliated PGC at least 20 business days before the auction starts, to allow enough time for evaluation and approval of credit. Potential bidders may submit the required documents after that time, but at the risk of not having credit and document approval in time for them to participate in the auction.

(iv) Credit approval for entities bidding on capacity auction products in ERCOT or in non-ERCOT areas of Texas will be performed pursuant to subsection (e)(7) of this section.

(v) The affiliated PGC shall notify an approved bidder of its available credit and send the approved bidder a completed capacity auction-specific version of the applicable Agreement, executed by the affiliated PGC, within ten business days after the bidder has submitted the required information. The approved bidder should attempt to execute and return the executed Agreement to the affiliated PGC no later than five business days before the auction starts. The executed Agreement shall be received by the affiliated PGC no later than two business days before the auction starts. The affiliated PGC shall provide a password or passwords to the approved bidder to allow access to the auction web site and to allow it to bid no later than one business day before the auction starts. An approved bidder may not request or receive additional credit after the auction starts.

(vi) Specific information on how to place bids and navigate the auction sites will be provided by the affiliated PGCs to their qualified bidders prior to the beginning of the capacity auction.

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

(A) Initial auction. For the initial auction in September 2001, each entitlement was 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) Schedule of subsequent auctions.

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

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

(iii) The auction in September 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 in November 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 in September 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 start 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 referenced in subsection (e)(1) of this section by 25 to determine the number of blocks of each type to be auctioned.

(B) Divisibility. If the amount to be auctioned for an affiliated PGC for a particular product is not evenly divisible by 25, any remainder shall be added to the product most highly valued in the immediately preceding auction for products of the same duration 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 shall pre-qualify by demonstrating compliance with the credit requirements in subsection (e)(7) 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 all of a seller's products of the same type and period. 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 would be a set of baseload-July 2002 entitlements.

(A) Method of auction for affiliated PGCs within ERCOT. Each auction shall be a simultaneous, multiple round, auction that includes procedures that allow switching by bidders between affiliated PGCs and product types.

(i) Auction duration. Once a product auction commences it will continue through each business day until that auction concludes.

(ii) Round duration. Each auction's first round will begin promptly at 8:00 a.m. and each round will last for 30 minutes with 30 minutes between rounds. For example, the first round of bidding will start at 8:00 a.m. and end at 8:30 a.m., the second round will start at 9:00 a.m. and end at 9:30 a.m., etc. No round may start later than 4:00 p.m. All times are in central prevailing time.

(iii) Credit calculation. An entitlement bidder's credit limit shall be adjusted during the auction based on the value of the entitlements bid upon, and will be determined by using an assumed fuel price stated by the entitlement seller, and the capacity price for the lesser of three months or the duration of the entitlement plus the amount that would be paid to exercise the entitlement for the lesser of three months or the duration of the entitlement at the assumed dispatch for each product as follows:

Product	**Peak Months (May-Sept.)**	**Off-Peak Months (Oct.-April)**
Baseload	100%	90%
Gas-intermediate	50%	20%

Product	Peak Months (May-Sept.)	Off-Peak Months (Oct.-April)
Gas-cyclic	20%	10%
Gas-peaking	10%	2%

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

(C) Method of auction for affiliated PGCs in non-ERCOT areas. Each auction shall be a simultaneous, multiple round, open bid 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 set of entitlements available for purchase at the auction. Each bidder will specify the number of entitlements 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 in any round is more than or equal to the available quantity, the affiliated PGC will adjust the price upward within the range for each specific product type as noticed according to paragraph (2)(B)(ii)(I) of this subsection. Bidders shall then submit bids for the quantities they wish to purchase of each set of entitlements at the new price. Subsequent rounds shall continue until demand is less than 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 equaled or 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 as described in clause (iii) of this paragraph.

(iii) Pro-rata entitlement allocation. The pro-rata allocation of entitlements will be implemented by determining a bid differential between the next-to-last round bid and the number of awarded entitlements based on the last round and awarding the remaining entitlement to the bidder with the largest differential. The awarded entitlement will then be subtracted from that bidder's differential and the process will iterate until all entitlements have been awarded. In the event that the differential between two or more bidders is the same, the tie will be broken based on the timestamp of each bidder's last bid submitted in the next-to-last round. For example, 14 baseload one-year strip entitlements are available and bidders A, B, C, and D are bidding. In the last round, demand was only 11 entitlements and bidder D did not bid.

Bidders	**Bids Next-To-Last Round**	**Last Round Bid**	**Awarded**	**Differential Between Rounds**
A	4 – 10:50	3	3	1
B	6 – 10:20	6	6	0
C	3 – 10:44	2	2	1
D	3 – 10:59	None – 0	-	3
Total	**16**	11 (3 leftover)	**11** **(3 avail)**	
In this example, bidder "D" would receive the first unsubscribed entitlement and its differential would be reduced by one since it possesses the largest differential.				

Bidders	**Bids Next-To-Last Round**	**Last Round Bid**	**Awarded**	**Differential Between Rounds**
A	4 – 10:50	3	3	1
B	6 – 10:20	6	6	0
C	3 – 10:44	2	2	1
D	3 – 10:59	None - 0	**1**	**2**
Total	**16**	**11** **(3 leftover)**	**12** **(2 avail)**	
Since bidder "D" still contains the largest differential and there are still two unsubscribed entitlements, "D" will again be awarded an entitlement.				

Bidders	Bids Next-To-Last Round	Last Round Bid	Awarded	Differential Between Rounds
A	4 – 10:50	3	3	1
B	6 – 10:20	6	6	0
C	3 – 10:44	2	2	1
D	3 – 10:59	None - 0	**2**	**1**
Total	**16**	**11 (3 leftover)**	**13 (1 avail)**	

For the last remaining entitlement there are three bidders that all have a differential of one: "A", "C", and "D". Therefore, a tie exists and the timestamp tiebreaker will be used to determine which of the three bidders should receive the entitlement. Based on the timestamps bidder "C" would receive the last entitlement, because it has the earliest time stamp in the next-to-last round. The completed auction would appear as follows:

Bidders	Bids Next-To-Last Round	Last Round Bid	Awarded	Differential Between Rounds
A	4 – 10:50	3	3	1
B	6 – 10:20	6	6	0
C	3 – 10:44	2	**3**	0
D	3 – 10:59	None - 0	2	1
Total	**16**	**11 (3 leftover)**	**14 (0 avail)**	

(iv) Auction duration. Once a product auction commences it will continue through each business day until that auction concludes.

(v) Round duration. Each auction's first round will begin promptly at 8:00 a.m. and each round will last for 30 minutes with 30 minutes between rounds. For example, the first round of bidding will start at 8:00 a.m. and end at 8:30 a.m., the second round will start at 9:00 a.m. and end at 9:30 a.m., etc. No round may start later than 4:00 p.m. All times are in central prevailing time.

(vi) Credit calculation. An entitlement holder's credit limit shall be adjusted during the auction based on the value of the entitlements awarded to the holder, which will be determined by using an assumed fuel price stated by the entitlement seller, and the capacity price for the lesser of three months or the duration of the entitlement plus the amount that would be paid to exercise the entitlement for the lesser of three months or the duration of the entitlement at the assumed dispatch for each product as follows:

Product	**Peak Months (May — Sept.)**	**Off-Peak Months (Oct. — April)**
Baseload	100%	90%
Gas-intermediate	50%	20%
Gas-cyclic	20%	10%
Gas-peaking	10%	2%

(D) Activity rules for affiliated PGCs in non-ERCOT areas.

(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.

(E) Mechanism for auction for affiliated PGCs in non-ERCOT areas. Each affiliated PGC shall conduct the auction over the Internet on a secure web page 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.**

(A) If an affiliated PGC intends to change the minimum opening bid prices that would otherwise be applicable under subparagraph (B) of this paragraph, it shall file with the commission, not less than 90 days before the auction start date on which the change is proposed to be applicable, a methodology for determining an opening bid price for each type of entitlement, if needed, based on the affiliated PGC'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 holders, 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. If no challenges are received, the affiliated PGC's proposed methodology shall be deemed appropriate. If any party objects to the affiliated PGC's proposed methodology, then the commission shall determine the appropriate methodology.

(B) Minimum opening bids for entitlements shall be the same as the minimum opening bids used in the most recent auction that included those entitlements, except that sellers with plants that have been affected by congestion zone changes since the most recent auction may use minimum opening bids that are different than the minimum opening bids in the most recent auction, provided that the seller maintains the same weighted-average, by MW, of the most recent auction's minimum bids, for all of its plants of the same product type in all congestion zones, to compute the new minimum opening bids for each product type. Nothing in this subparagraph shall prevent the commission from ordering a different methodology for a seller, if the seller proves that good cause exists for the change.

(C) 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 be deemed to have met the 15% requirement if it offered products in a product category (for example, gas-intermediate) and successfully sold, at least, all of the entitlements offered in one particular month, in that product category. If there is an auction where there is no month in which all of the entitlements of a particular product are sold, then the affiliated PGC shall, in its notice pursuant to paragraph (2)(B)(i) of this subsection, make a proposal to the commission in order to comply with the 15% requirement. The affiliated PGC's proposal may include revisions to the product category, product price, or offer alternative products for auction.

(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.

(i) **Resale of entitlement.**

(1) **Compliance with provisions.** An entitlement may be assigned, sold or transferred by the entitlement holder only by following the provisions of this section. Any purported assignment, sale, or transfer of an entitlement that does not follow the provisions of this section is void and ineffective against the affiliated PGC.

(2) **Eligible entities.** An entitlement holder may assign, sell, or transfer an entitlement to any person or entity other than an affiliated REP, but the entitlement holder may dispatch the output of the entitlement to an affiliated REP.

(3) **Obligations.** An entitlement that is assigned, sold, or transferred under this section remains subject to the provisions of the Agreement under which it

originated, and the assignee of that entitlement succeeds to all of the rights and obligations of the assignor with respect to that entitlement.

(4) **Liability.** Neither the assignor nor any previous entitlement holder that has remained liable for payments due to the affiliated PGC in connection with the entitlement as a result of a previous assignment, sale, or transfer is released from liability to the affiliated PGC for payments due in connection with the entitlement unless:

(A) At least 14 days before the effective date of the assignment, sale, or transfer, assignee has provided security to the affiliated PGC that is equal to or greater than the security originally given to the affiliated PGC for the entitlement; and

(B) At least ten days before the effective date of the assignment, sale, or transfer, the affiliated PGC has notified both assignor and assignee in writing that the security has been approved and accepted by the affiliated PGC.

(5) **Requests to approve security.** The affiliated PGC shall respond to written requests to approve security to be offered by a prospective assignee within 14 days after receipt of that request. Approval shall not be unreasonably withheld.

(6) **Effective date.** No assignment, transfer, or sale of the entitlement by a party is binding on the non-assigning party until the non-assigning party receives written notice of the assignment, sale, or transfer and a copy of the executed assignment, sale, or transfer document, and the assignment, sale, or transfer is not effective

unless such notice is received at least three days before the beginning of the entitlement month.

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

(1) **Process.** For 2002 and 2003,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 ECOM model to estimate stranded costs for the affiliated PGC in the PURA §39.201 proceeding.

(2) **PGCs without stranded costs.** 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.

(3) Any order by the commission that finally resolves an affiliated PGC's stranded costs, prior to true-up, supersedes this subsection.

(k) **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.

(l) **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 section.

(m) **Contract terms.**

(1) **Standard agreement.** Parties shall utilize the Agreement in the form prepared by the Edison Electric Institute (Version 2.1). The Cover Sheet to the Agreement shall provide for credit terms that are based upon objective credit standards determined by the commission. There may be different versions of the Agreement applicable to sales of capacity auction products in different regions in Texas. For example, ERCOT and the non-ERCOT areas may have different versions of the Agreement.

(2) **Applicability.** The terms and conditions set forth in any Agreement apply only to the entitlements obtained in the capacity auctions under this section.

(3) **Electronic scheduling.** The Agreement shall require that, if the affiliated PGC provides an electronic scheduling interface for the dispatch of entitlements, then the entitlement holder shall schedule the dispatch of its entitlements using that electronic interface.

(4) **Scheduling discrepancies.** If an entitlement holder submits a non-conforming schedule to the affiliated PGC for an entitlement that violates any of the scheduling requirements for that capacity auction product type for a scheduled hour, then the schedule for that hour is deemed to be the same as the schedule for the hour most closely preceding that scheduled hour that was not a non-conforming schedule.

The affiliated PGC shall promptly notify the entitlement holder of a non-conforming schedule. However, the requirements of this paragraph are subject to the default scheduling requirements for baseload and gas-intermediate products delineated in subsections (f)(3)(A)(iv)(V) and (f)(4)(A)(v) of this section for ERCOT areas, and subsections (g)(2)(E)(v) and (g)(3)(E)(v) of this section for non-ERCOT areas.

(5) **Alternative dispute resolution.** Alternative dispute resolution shall be a condition precedent to any right of any legal action regarding a dispute arising under, or in connection with, the standard agreement adopted by the commission. The parties may mutually agree to dispute resolution procedures. If the parties are unable to agree upon such procedures within five days after such dispute arises, the parties shall use the alternative dispute resolution procedures contained in the ERCOT protocols.

(6) **Seller's failure to fulfill obligation.** If an entitlement holder is assessed for imbalanced schedules, failure to procure ancillary services, or any other charges from ERCOT due to the failure of the affiliated PGC to fulfill the auctioned obligation, the affiliated PGC shall be responsible for these costs incurred by the entitlement holder.

(n) This section, as adopted, becomes effective on August 1, 2002.

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 JUNE 2002.

PUBLIC UTILITY COMMISSION OF TEXAS

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Rebecca Klein, Chairman

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Brett A. Perlman, Commissioner