PROJECT NO. 27917

RULEMAKING ON PRICING SAFEGUARDS IN ERCOT-OPERATED WHOLESALE MARKETS	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING NEW §25.502
AS APPROVED AT THE DECEMBER 2, 2004 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts new §25.502, relating to Pricing Safeguards for Markets Operated by the Electricity Reliability Council of Texas (ERCOT), with changes to the proposed text as published in the June 25, 2004 issue of the *Texas Register* (29 Tex Reg 6015). This is a competition rule subject to judicial review as specified by Public Utility Regulatory Act (PURA) §39.001(e). The rule is adopted under Project Number 27917.

A public hearing on the rule was held at commission offices on August 2, 2004, beginning at 9:39 a.m. Representatives from City of Austin d/b/a/ Austin Energy (Austin Energy); Reliant Energy, Inc. (Reliant); the City of San Antonio, acting by and through City Public Service Board of Trustees (San Antonio); Tractebel Energy Marketing, Inc. (Tractebel); and TXU Portfolio Management Company LP, TXU Generation Company LP, and TXU Energy Retail Company LP (TXU) made comments at the hearing and also provided written comments. In addition, American National Power, Inc.; Calpine Energy Services, LP; Constellation Power Source, Inc.; Coral Power, LLC; Exelon Generation Co., LLC; FPL Energy, LLC; Mirant Americas Energy Marketing, LP; PSEG Texgen I, Inc.; Sempra Global; Texas Independent Energy; Bastrop Energy Partners, LP; CPL Retail Energy, LP; Direct Energy, LP; Kiowa Power Partners, LLC; Tenaska Frontier Partners, Ltd.; Tenaska Gateway Partners, Ltd.; Tenaska III Texas Partners;

and WTU Retail Energy, LP (collectively, Joint Commenters) made joint comments at the hearing and also provided written joint comments.

In addition to the comments received from the above-listed entities, the commission also received written comments on the rule from AEP Texas Central Company and AEP Texas North Company (AEP); Alliance for Retail Marketers (ARM); BP Energy Company (BP); Brazos Electric Power Cooperative, Inc. (Brazos); DFW Electric Consumer Coalition (DFW Coalition); ERCOT; Lower Colorado River Authority (LCRA); Office of Public Utility Counsel (OPC); South Texas Electric Cooperative (STEC); Texas Commercial Energy (TCE); Texas Genco, LP (Texas Genco); and Texas Industrial Energy Consumers (TIEC).

In the preamble for the proposed rule, the commission identified seven specific issues upon which it sought comment. Those issues are listed below.

Issue 1: System-Wide Price Safeguards

Subsection (i) is intended to place a reasonable constraint on prices when the market is not competitive system-wide and prices cannot be determined by the normal forces of competition. In particular, it would preclude a pivotal supplier or "hockey stick offer" from setting any clearing price. "Hockey stick pricing" is when a supplier prices most of its offer competitively, but prices a small, economically expendable portion exorbitantly high. The basic mechanism included in subsection (h), referred to as the Competitive Solution Method (CSM), was developed by Staff and first proposed in Docket Number 24770, Report of the Electric Reliability

Council of Texas (ERCOT) to the PUCT regarding Implementation of the ERCOT Protocols. In that docket, the commission approved a limited form of CSM for quick implementation, and decided to defer further consideration of CSM to a rulemaking, such as this one, dealing more broadly with market failure mitigation. See Docket Number 24770, Order (August 22, 2003), pages 26-27. While CSM is designed to be automatic, the ERCOT white paper addresses hockey stick pricing by relying on the independent market monitor (IMM) to identify and remove hockey stick offers on an ad hoc basis prior to market clearing. Another difference is that CSM automatically mitigates the influence of suppliers who are pivotal on a system-wide basis, while the ERCOT white paper does not. Please compare the automatic mitigation contained in the rule to the ad hoc mitigation in the white paper as well as practices in other markets (for example, New York's Automatic Mitigation Procedure), and explain why one is preferable over the others.

The bulk of the comments submitted in this rulemaking pertained to CSM. One general theme running through many of the written comments (*i.e.*, those submitted by AEP, ARM, Austin Energy, Brazos, ERCOT, Joint Commenters, LCRA, Reliant, San Antonio, and TXU) as well comments made at the public hearing was that the commission should defer consideration of CSM until the completion of the Texas Nodal Team (TNT) stakeholder process at ERCOT and the finalization of the new wholesale market design. LCRA and TXU observed that TNT stakeholders are still considering and developing market design features that would address the same problems CSM was designed to address. Among the alternatives are ERCOT's procurement of energy and reserve capacity in the same auction (*i.e.*, co-optimization of energy and capacity), and use of a small amount of responsive reserve capacity for energy deployment according to an established price curve. TXU noted that some of these proposals are similar to an approach suggested as a CSM alternative by Dr. Shmuel Oren, Senior Advisor to the commission's Market Oversight Division, at recent TNT stakeholder meetings. In reply comments, Joint Commenters and Reliant said these alternatives were preferable to CSM.

As a general matter, Austin Energy, Joint Commenters, LCRA, Reliant, Tractabel, Texas Genco, and TXU opposed CSM and preferred the ERCOT white paper approach, while consumers BP, DFW Coalition, OPC, STEC, TCE, and TIEC favored CSM and said the white paper approach would be inadequate. OPC and TIEC stated that implementation of proposed subsection (i) should not wait until 2006, while ARM opposed the provision.

Few commenters offered any comparison with New York's Automatic Mitigation Procedure (AMP) or other mitigation approaches used in other electricity markets, although Reliant said that monitoring by an IMM as proposed in the ERCOT white paper was preferable to AMP. TXU, on the other hand, commented that the use of selective mitigation (which is one of the main features of AMP) is one of the preferred methods of regulation, and has precedent in power market regulation. TCE recommended a modification to the proposed CSM methodology based on mitigation in the PJM Interconnection (PJM): capping the offer prices of pivotal suppliers at 10% over their verifiable costs, rather than setting a system-wide price cap applicable to all suppliers.

Joint Commenters recommended as an alternative to CSM limiting the slope of the portion of any offer curve above \$300 or below -\$300. Any offer that failed the screen would be rejected and therefore would not set any market price. Joint Commenters stated that such a screen would address the problem of hockey stick pricing identified in the preamble to the proposed rule. In its reply comments, however, TIEC criticized the bid slope screen, because it would be easy to circumvent and would not prevent a supplier from bidding up the nodal price to an unjustified level in a constrained area. TIEC stated that CSM is activated when a pivotal supplier exists and when supply margins fall below a specified threshold, providing appropriate consumer protections against market power abuse and ensuring that mitigation is applied only when market conditions warrant such measures.

Most specific comments in opposition to CSM fell into four general categories:

- The merits of ex-post mitigation over ex-ante mitigation;
- The need for scarcity pricing and the benefits of price volatility;
- Problems with how CSM would be implemented, including its applicability to congestion revenue rights (CRRs) and day-ahead markets; and
- The commission's legal authority to mitigate prices.

Ex post versus ex ante. Austin Energy commented that while ex-ante mitigation is quick and automatic, it risks being overly broad, and that when applied injudiciously can suppress market activity and limit price signals to suppliers. On the other hand, while ex-post mitigation may require more resources, it can be applied very specifically to instances in which it is demonstrated that a market participant committed an actionable violation, and thus will have less impact on market activity and price signals. Austin Energy favored the mitigation approach contained in the market white paper authored by the TNT Market Mitigation Concept Group

(TNT-MMCG), stating that ex-ante measures should be reserved for situations in which case-by-case review of market participant behavior would be difficult to undertake and hard to identify, and where the risk from failure to act to protect the market from abuse is extremely high. Austin Energy stated that hockey stick pricing is easily identified and that under the TNT approach, the IMM may simply discard the hockey stick offers.

LCRA and Reliant stated that market power mitigation as related to bidding behavior should emphasize physical withholding, which Reliant further noted is a prohibited activity under P.U.C. Substantive Rule §25.503(g)(7). The TNT-MMCG approach is expected to detect such behaviors in the current TNT framework, Reliant and LCRA stated.

Scarcity pricing. Austin Energy, Joint Commenters, Reliant, Texas Genco, and TXU expressed concern that CSM would result in over-mitigation that would suppress prices to such an extent that it would provide a disincentive for new generation. Texas Genco stated that an offer that may appear to be a “hockey stick” may be the result of a generation entity’s actual costs and associated risks of running at high generation levels. TXU opined that because CSM automatically mitigates bids every time there is less than 101% of the supply needed in the real-time energy market, or less than 105% of the supply needed in the ancillary services markets or day-ahead markets, legitimate scarcity pricing would be eliminated under CSM. Joint Commenters stated that the undesirable effects would be particularly magnified when combined with ERCOT’s lack of a forward resource adequacy requirement.

TXU also stated that CSM would make it very difficult for potential generation investors or transmission and distribution utilities to see the legitimate local scarcity pricing signals that would induce economically efficient generation and transmission investment at locations where it is needed.

Austin Energy opined that the need for CSM has not been demonstrated, and that mitigating price spikes could deprive the market of necessary short-term incentives to bring more supply to the market. Austin Energy referred to an April 30, 2002 price spike in the market for non-spinning reserve service cited in the preamble to the proposed rule, and stated that the increase in offers for the two weeks following the spike could plausibly be attributed to the spike. Commission staff had estimated the impact of the April 30 price spike to be approximately $6 million, but Austin Energy concluded that the price spike may also have reduced the cost of non-spin in subsequent weeks. According to Austin Energy, the additional supply induced into the market by the price spike plausibly lowered the price for NSRS. ARM and Austin Energy recommended that prior to adopting CSM, the commission conduct a study of how the current application of CSM in the balancing energy market has affected supply.

BP cautioned that mitigation measures should not employ mechanisms that are focused only on achieving low prices in the short run, and that do not allow for appropriate returns on invested capital located in transmission constrained areas. BP generally supported CSM for generation resources, but added that the process ultimately adopted by the commission should be more transparent than what was represented in the proposed rule. According to BP, CSM should be designed so that it does not remove competitive economic offers, and should not be triggered if the market clearing price of energy (MCPE) is set by a load acting as a resource.

Implementation. Reliant stated that it was unclear whether CSM's pivotal supplier test was to be applied to the entire energy market, or to the incremental amount needed to ensure system sufficiency. Reliant stated that the proper approach would be to test whether the additional energy needed from one interval to the next could be provided by the market, without any one supplier being pivotal. Over-mitigation could result, Reliant stated, if one or two major suppliers were pivotal in meeting all load obligations, but were not pivotal in meeting any incremental change between intervals.

Pursuant to its comment that mitigation should focus on withholding, Reliant stated that CSM's supply test should first calculate the generation available for security-constrained economic dispatch (SCED) in the real-time market (all remaining bids in the real-time market, plus all megawatts currently loaded as resources), plus awards and self-provision of ancillary capacity services. This sum would then be compared to the total on-line capability of all resources as currently reported in the operating plan. If total on-line capability exceeds the total available generation for the SCED (including ancillary services) by a set threshold, then CSM would apply. Reliant said that if the benchmark were not exceeded, there would be no effective withholding and CSM should not apply.

Reliant also questioned how CSM would deal with virtual bidding in a day-ahead market, and stated that if transmission congestion were not cleared day-ahead, it would be inappropriate to apply CSM to the day-ahead market because there would be no link between financial and physical arrangements. Reliant cautioned, however, that at this time TNT stakeholders are carefully considering comments by economic experts recommending that congestion be cleared day-ahead. Reliant stated that if TNT stakeholders agree to that suggestion, CSM may be a viable day-ahead mitigation measure if Reliant's recommended changes were made. LCRA also stated that CSM may be appropriate in a non-voluntary day-ahead market if CSM is also applied to the real-time market, but stated that if the day-ahead market were voluntary as currently contemplated in the TNT design, mitigation would not be necessary.

TXU stated that if CSM were adopted, the commission should clearly define each market to which the tests would be applied; replace the quantity test with a more direct measure of physical withholding; modify the pivotal supplier test to account for long-term obligations and inflexible plants; exclude small suppliers (ones with less than 5.0% of the market) from the definition of pivotal supplier; apply the cap only to suppliers who fail the pivotal supplier test; and base the proxy price on a historical benchmark rather than an arbitrary 50% adder.

Commission authority. Austin Energy, Joint Commenters, and Tractebel asserted that the commission does not have authority to mitigate prices as proposed under CSM. In particular, Joint Commenters stated that PURA §39.001(a) expressly finds that competition in wholesale power markets exists such that wholesale prices should not be set by regulation. Joint Commenters also cited PURA §35.004(e), concluding that the process by which market participants sell electricity to ERCOT is by statute deemed not to be unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive.

Austin Energy stated that the commission's authority to pursue any type of market mitigation is, under PURA, predicated on the existence of market power. As CSM does not include a demonstration of market power abuse or even a finding of market power, Austin Energy stated that restricting prices through CSM is not within the commission's regulatory authority. Austin Energy further stated that the commission's rulemaking to define market power was too late to be relied on in the current rulemaking. Joint Commenters stated that even when market power is found to exist, mitigation through price restrictions is not a remedy that is permitted by PURA. Tractebel stated that price mitigation cannot artificially limit a generator's recovery to its short-term marginal cost, and that under the 5th and 14th Amendments of the United States Constitution, the "due course of law" provision of the Texas Constitution, and PURA, any price cap or mitigation must protect generators' ability to achieve market-based returns.

In reply comments, OPC and STEC disagreed with Joint Commenters, Austin Energy, and Tractebel, stating that the legislature gave the commission authority to protect the market from abusive pricing. CSM does not set a rate certain, OPC said, and does not even address rates that are outside of the pricing of congestion resulting from transmission constraints and the pricing of ancillary services. STEC and OPC stated that PURA gives the commission authority to establish terms and conditions for ERCOT's dispatch functions after the introduction of customer choice. OPC further replied that Joint Commenters erred in their interpretation of PURA §35.004(e), in that the statute applies assuming that ancillary services are provided on a non-discriminatory basis. OPC stated that the nature of hockey stick bidding discriminates against buyers in favor of sellers, and is not based on competitive pricing. Joint Commenters' argument only has merit if competition is truly functional and no structural discrimination exists, OPC stated.

Commission Response

The commission agrees that adopting CSM in this rulemaking would be premature given the on-going discussions at ERCOT with respect to market design. At the same time, however, it would also be premature to withdraw CSM from consideration.

The commission reminds all commenters that CSM was designed to address two problems: "hockey stick" pricing (offers that include a small quantity priced extraordinarily high) and market distortions caused by pivotal suppliers. Unless both problems are adequately addressed, CSM will remain an option for a future rulemaking.

Regarding the call by OPC and TIEC to implement CSM immediately rather than waiting until 2006, the commission notes that a form of CSM is already in place, pursuant to the commission's final order in Docket Number 24770. This mechanism has been activated a number of times since August 2004, after a long period during which it was triggered very seldom. Commission staff is at this time investigating the causes of the price excursions that have triggered this modified version of CSM, but that inquiry will not be completed within the timeframe of this rulemaking. The commission finds that although the concerns raised by OPC and TIEC are valid, commission staff's analysis of the recent price spikes is needed in determining specifically how the current mitigation mechanism should be revised. The commission therefore declines to use this rulemaking to change the current implementation of CSM.

Proposed subsection (i) includes an offer cap of $1,000/MWh or $1,000/MW/h. No comments were made on this offer cap. This offer cap codifies prior commission orders, and is necessary to help ensure reasonable ancillary service prices. Consequently, the commission has retained this offer cap in the rule.

Issue 2: Offers Priced Above System-Wide Cap

The system-wide mitigation approved by the commission in Docket Number 24770 allows mitigated offers to be paid at their offer price if selected, but prevents them from setting any market clearing price. By contrast, the proposed rule would preserve such treatment only for loads acting as resources, and would pay all other offers at the greater of the system-wide offer cap or their verifiable costs. An alternative approach would be to adopt the offer cap contained in the TNT Market Mitigation White Paper, which is intended to address local market power only. The TNT approach for mitigating local market power would cap offers at the greater of verifiable costs plus an adder based on the unit's historical capacity factor, or a general fixed heat rate equivalent. If the system-wide offer cap in subsection (i) is ultimately adopted by the commission, what is the best way to treat offers that are priced above that cap?

Austin Energy stated that if the commission were to proceed with CSM, loads acting as resources (LAARs) should be treated as all other resources to the greatest extent feasible. In this instance, Austin Energy said, an offer from a LAAR that is priced above the system-wide offer cap should simply be deleted from the offer stack, as described in the TNT-MMCG white paper.

BP favored paying as bid for selected generation offers priced above the CSM cap if the supplier could demonstrate that the offer was economically legitimate. However, BP also said CSM should not apply at all to prices set by LAARs.

LCRA said that any scheme to pay verifiable costs that did not also let such costs set nodal prices would necessarily lead to uplift. LCRA favored using the approach endorsed by TNT for local market power: capping offers at the greater of the systemwide offer cap or the unit's pre-approved verifiable cost plus a specified adder. Texas Genco expressed a similar preference, although reiterating its recommendation that CSM not be adopted at all.

Joint Commenters stated that the current method of paying any above-cap selected offer as bid was preferable to paying only LAARs as bid, adding that such a distinction would constitute classic discrimination. Joint Commenters further stated that recovery above the system-wide offer cap would need to provide for recovery of verifiable costs and an adder that in total allows recovery of all costs, including capital costs and a return of and on investment. Reliant agreed that no distinction should be made between generation resources and LAARs, and that both should be paid their offer prices.

STEC agreed with paying LAARs as bid, but added that it would be reasonable to pay all other selected resources priced above the system-wide cap the greater of the cap or their verifiable costs, including recovery of capital costs over and above expenses.

OPC stated that selected offers priced above the system-wide cap should be paid as bid.

TIEC stated that selected offers priced above the system-wide cap should receive no more than their verifiable short-run costs plus a reasonable fixed adder.

Commission response

Withdrawal of CSM for the reasons previously stated makes it unnecessary to decide at this time how to treat selected offers that are priced above a system-wide mitigated offer cap.

Issue 3: Congestion Revenue Rights

Market participants that own both resources and CRRs under certain circumstances can use the combination to enhance profits associated with causing congestion. The white paper directs the market monitor to review the interaction between ownership of CRRs and generation and take the appropriate remedial action, but imposes no pre-determined ownership limits. Subsection (k) of the proposed rule presents a specific, pre-determined approach to CRR holdings consistent with the general guidelines mentioned in the white paper, except that it establishes certain limitations on CRR holdings. Please compare the specific, pre-determined approach to CRR holdings in the rule to the ad hoc approach in the white paper, and explain why one is preferable over the other.

BP supports proposed paragraph (k)(1), because expedited disclosure should facilitate more liquid and competitive secondary markets. Joint Commenters stated that the commission should clarify in proposed paragraph (k)(1) the information that would be published and needs to define the term “beneficiaries.” Joint Commenters stated that public disclosure of specific quantities of CRRs on a point-to-point basis or identifying loads could reveal trade secrets and competitively sensitive information. The Joint Commenters suggested that publishing the names of CRR owners and the total percentage of flowgate CRRs owned would be acceptable.

BP, Brazos, LCRA, OPC, and Texas Genco were concerned that the proposed CRR limits in proposed paragraph (k)(2) are unduly restrictive or difficult to implement. Brazos was concerned that proposed paragraph (k)(2) is an arbitrary approach to resolve a potential market power problem, and could limit ownership or control of resources in a constrained area to address a potential, rather than real, problem. BP stated that the paragraph would be unnecessary to prevent gaming and would needlessly degrade efficiency and competition in retail and wholesale markets. BP believes that not allowing market participants to be long on CRRs will inhibit the ability of load-serving entities (LSEs) and power marketers to compete for legitimate business in a load pocket. BP averred that the holding of CRRs and the purchase of contracts need to be decoupled for an active and liquid secondary market in delivered energy. OPC stated that a limit on CRR holdings may limit the ability of some market players to hedge themselves.

BP suggested that the commission establish limits on CRR holdings such that an entity is not allowed to hold more than 25% of the capacity on a constraint above its demonstrable load minus controlled generation on the importing side of a transmission constraint. BP stated that

NYMEX imposes similar limitations on speculative holdings in its futures markets. Brazos prefers event-specific limitations rather than using pre-determined limitations on CRRs. LCRA does not see a need to impose CRR ownership limits on non-competitive constraints, since any attempt to manipulate prices is mitigated automatically by the proposed TNT-MMCG local market power mitigation process. Therefore, according to LCRA, the rule needs to focus on competitive constraints. LCRA suggested that as an alternative, ERCOT should pay a CRR holder that owns more than 25% of a particular competitive constraint the lesser of the shadow price of the impacted constraint or the greatest shadow price of the constraint in all previous CRR auctions that included the relevant time interval, for the quantity above the 25% limit, if the CRR holder controls a significant amount of generation resources on the importing side of the constraint.

TIEC supported limits on CRR holdings, stating that there is no valid reason for a supplier to hold CRRs for a constraint in excess of those needed to fully cover its local load requirements. The DFW Coalition and OPC stated that limits on CRR ownership was an acceptable alternative. STEC supported limitations on CRR holdings comparable to those currently applicable within ERCOT.

The DFW Coalition and OPC preferred to mitigate CRRs by allocating CRRs to load rather than auctioning them to the highest bidder. According to OPC, the market will benefit in two ways. First, CRR allocation keeps CRRs out of the hands of entities that can benefit from causing congestion. Second, CRR allocation allows loads to hedge against some of the price risk of going to a locational marginal pricing system. TIEC supported restricting ownership of CRRs to loads.

CPS, Reliant, TIEC, and TXU stated that the commission needs to clearly define the term "local load." LCRA stated that in an unbundled ERCOT market, it is almost impossible to determine local load served by a qualified scheduling entity (QSE). ERCOT and TIEC stated that the commission would need to define in more detail the term "effective local resource capacity." TIEC also stated that the commission should establish the appropriate implementation details of proposed paragraph (k)(2). Reliant stated that the rule could be amended to consider all transmission import constraints into a load zone and the load obligations and effective load resource capacity that impact transfers into the load zone. TIEC rejected this approach, stating that the use of ERCOT load zones would mask constraints within the zone where CRR ownership restrictions would be appropriate.

Commission response

The commission notes that at this time, TNT stakeholders are still discussing market design options that may affect the need for proposed subsection (k). Therefore, as with CSM, the commission defers its decision on pricing safeguards related to CRRs. The commission will address this issue as part of its review of the draft protocols to be submitted pursuant to P.U.C. Substantive Rule §25.501.

Issue 4: Disclosure of Resources with High Offer Prices

Under the current market, ERCOT posts a list of all market participants who submit offers priced above $300 per megawatt-hour (MWh) for balancing energy service and $300 per megawatt per hour (MW/h) in the case of ancillary capacity services. The list is posted the following operating day. Subsection (d) of the rule continues this disclosure in the new market. In addition, any offer above $300 that actually causes a price to clear above $300 would also be identified as a price setter. Is extending the current disclosure practice an appropriate deterrent to hockey stick pricing?

A number of parties submitted responses in support of the disclosure requirements of proposed subsection (d). Of the parties supporting this proposed provision, ARM, Brazos, DFW Coalition, OPC, Reliant Energy, Texas Genco, and TIEC did so without qualification, and noted the positive effects that disclosure of certain prices has had on the market to date.

ARM supported the proposed subsection, and stated that it does not believe that the proposed subsection's requirements regarding disclosure of offer prices will hamper the nodal market development process. Likewise, Brazos was in support of proposed subsection (d) and noted the beneficial effect of the rule in creating "peer pressure" on market participants to maintain pricing below $300. Brazos also contended that the current disclosure practice provides an adequate deterrent to hockey stick pricing.

The DFW Coalition joined in support of the proposed subsection. The DFW Coalition observed that the highest cost generator in ERCOT would likely operate in the $80-$90 per MWh range under normal market conditions.

OPC noted the success of the current disclosure practice, and argued that it should be extended. OPC stated that as the commission has ordered the disclosure of offers above a given threshold, bids have converged to a level just below the disclosure price. According to OPC, ERCOT's disclosure requirement is a best practice, and so OPC supported the adoption of proposed subsection (d).

TIEC supported extension of the current disclosure practice as described in proposed subsection (d). This disclosure, in TIEC's view, generates transparency and allows regulators to identify bad actors in the marketplace. TIEC supported proposed subsection (d) regardless of whether ERCOT establishes a nodal market.

Reliant stated that self-policing has been an effective deterrent against abusive bidding behaviors, and so contended that the disclosure requirements of proposed subsection (d) should be extended into the new market design. Texas Genco stated that the current disclosure process has been an effective mitigation measure and supported extending the current process to the new market.

Several of the commenters supported the general principle of disclosure as embodied in proposed subsection (d), but proposed modifications. Austin Energy, ERCOT, TCE, and TXU suggested several potential changes to proposed subsection (d). Austin Energy did not object to proposed subsection (d), but stated that proposed subsection (d)(3) is not necessary if the commission adopts its recommendations with respect to Issue No. 2, offers prices above the system-wide cap.

ERCOT affirmed that its systems currently support the disclosure process, but observed that supporting disclosure as required by the proposed rule might increase ERCOT's workload, as it would have to review additional bids under the rule. This is because ERCOT will operate the security-constrained, day-ahead energy market, and bidding will be resource-specific rather than portfolio-based. ERCOT also requested two business days, rather than one market day, to make the disclosure posting.

TCE noted the effectiveness of disclosure as a market mitigation measure, but suggested that lowering the threshold for triggering a disclosure obligation would be even more effective. Specifically, TCE proposed that a company be required to identify itself if it bids in excess of 20 MMBtu/MWh x Fuel Index Price. Furthermore, if a company bids in excess of 30 MMBtu/MWh x Fuel Index Price, TCE would have that company's entire bid curve posted on ERCOT's website and require the company to identify which unit is the basis for its highest offer price. TCE noted generally the usefulness of more information to market participants.

TXU recommended deletion proposed subsection (d)(3), which requires that the identity of any resource that is paid more than the system-wide offer cap be published. TXU argued that this provision is not necessary, because any resource that is paid above the system-wide offer cap will already have been identified under proposed subsection (d)(1). Additionally, TXU noted that any resource that is paid above the system-wide offer cap will not be permitted to set the market price, under proposed subsection (i)(3). In TXU's view, this is sufficient, and any additional disclosure is merely additional stigmatization. If the resource can provide verifiable costs above the system-wide offer cap, TXU stated, there is no reason to stigmatize the resource at all.

Other commenters did not support the adoption of proposed subsection (d) at this time. BP argued that extending the current ERCOT disclosure practice will provide no additional deterrent to hockey stick pricing compared to what will be provided by the proposed CSM-IMM processes. BP argued that if the commission adopts CSM as proposed, hockey stick pricing will be mitigated ex ante. As a result, BP concluded that implementing both CSM and a new disclosure requirement would not provide an additional benefit equal to the cost of maintaining two concurrent and redundant systems. BP asserted that the proposed disclosure regime may be ceased with the elimination of "as bid" pricing for generation offers which exceed the CSM derived price cap in proposed subsection (i).

AEP argued that there is no additional benefit to expanding the current disclosure requirements. AEP stated that it is relatively easy to determine the identity of the entity setting market clearing prices above $300 under the current disclosure requirement, and that the new disclosure requirement contained in proposed subsection (d) imposes additional administrative processing and posting burdens on the ERCOT staff.

Commission response

Like CSM itself, this provision is intended to deter excessive offer prices. TIEC stated that the disclosure regime embodied in proposed subsection (d) would be beneficial in the current market. The commission agrees and has amended the subsection to clarify that it applies to the current market as well as to any future market. The identity of the entity will be disclosed, along with the corresponding settlement interval and market location (*e.g.*, congestion management zone in the current system or a node in a nodal market design), and the commission has defined the term "market location." The commission's amendments to this subsection reflect the value of disclosure to promote fair competition, irrespective of other changes to the market.

The commission rejects AEP's suggestion that there is no additional benefit to the new disclosure requirements set forth in proposed subsection (d). The new requirement in the proposed subsection, that a resource be identified as the price setter if its offer sets a price higher than $300, is intended to single out the price setter from lower-priced offers when prices exceed $300. For example, if gas prices force a number of suppliers to offer energy or capacity slightly above $300, and a lone hockey stick offer causes the price to clear at $990, the market (and the public) will be able to correctly identify the entity responsible for the $990 price, instead of indiscriminately blaming all the suppliers who offer slightly above $300 but were nowhere near $990.

The commission understands the additional burden that proposed subsection (d) and other subsections of this rule may present to ERCOT, and appreciates ERCOT's statement that

it is prepared to accept the additional administrative burden of reviewing offers under the rule as proposed. However, the commission does not believe that requiring posting within two business days, as recommended by ERCOT, is appropriate for paragraphs (d)(1) and (2). By setting the posting deadline in terms of business days, ERCOT's proposal would at times lead to several days' delay in posting offers qualifying under the rule. The commission believes that it is important for the market to have this information quickly, and therefore declines to set the posting deadline in terms of business days. However, the commission finds that publishing the information by noon the next day (rather than 8 a.m. as originally proposed) will not seriously compromise the benefits of disclosure.

The commission acknowledges that disclosure of the information required by paragraph (d)(3) is dependent on the calculation of the corrected market clearing price. This provision is therefore amended to require disclosure concurrent with the publication of the corrected market clearing price.

Issue 5: Safe Harbor

Subsection (j) would provide market participants with a limited safe harbor against enforcement actions dealing with certain kinds of market power abuse. Please comment on the appropriateness and effectiveness of such a safe harbor.

Several commenters opposed the inclusion of proposed subsection (j), and the remaining commenters voiced reservations about certain aspects of the proposed subsection.

Asserting that proposed subsection (j) is flawed on two counts, Austin Energy recommended its deletion. Austin Energy criticized the phrase "worked as intended" as vague and raising the specter of arbitrary enforcement; at the least, the commission's interpretation of the phrase should be precisely specified. In addition, Austin Energy condemned proposed subsection (j) as being inconsistent with basic principles of economics in suggesting that market power could be non-persistent. According to Austin Energy, market power by definition requires the ability to raise and sustain uncompetitively high prices. Austin Energy maintained that any other interpretation of market power should be thoroughly debated in the upcoming rulemaking on market power.

Texas Genco also favored deleting proposed subsection (j), asserting that its provisions constitute less a safe harbor for market participants than a safety net that would allow the commission to mitigate prices even if the proposals in subsections (h) and (i) fail to work.

In reply comments, Joint Commenters agreed with Texas Genco's remarks, and recommended deleting proposed subsection (j), or at a minimum, proposed paragraph (j)(3). They asserted that the language "work as intended" is unconstitutionally vague; that the rule is unconstitutionally retroactive and exceeds the commission's authority; and that it denies market participants contract certainty and creates unworkably high risk. In addition, Joint Commenters objected to the term "persistent market power," noting that appropriate definitions of "market power" have not been explored; they also agreed with Austin Energy that "market power," properly defined, requires persistent power.

TCE recommended deleting proposed subsection (j) for a different reason. It stated that it is unclear if there currently is any venue for a consumer hurt by market-power abuse to seek remedy, and that if the commission is the only venue in which such victims can seek relief, the safe-harbor provision is inappropriate. Rather, TCE opined, the commission should expand its tools to remedy market-power abuses, which can have consequences much greater than just excessive costs in specific intervals.

Reliant also favored deleting proposed subsection (j). Its key criticism was that it is inappropriate for the commission to require the disgorgement by all market participants of profits received from prices that resulted from market-power abuse that was not satisfactorily mitigated. It contended that this provision would have serious adverse commercial effects. Load could be discouraged from acting as a resource in the market, because of increased uncertainty as to the price it would receive for interruption. Higher LAAR offers would also likely result as loads incorporate higher risk premiums in their offers. In addition, retail electric providers (REPs) that structured retail products based on the MCPE would also be affected by resettlement. Reliant also noted that the Federal Energy Regulatory Commission (FERC) has rejected the "make the market whole" approach in its Order Amending Market Based Tariffs and Authorizations; instead, FERC opted to consider potential disgorgement on a transaction-specific basis. Finally, Reliant asserted that the subsection would authorize the commission to take action beyond the authority granted by PURA §39.157, which does not authorize the commission to disgorge profits via a resettlement of the entire market.

TIEC advocated deferring consideration of safe-harbor provisions, contending that the commission should first implement the proposed rule's price protections and allow a reasonable time for them to be tested in the market. Additionally, TIEC complained that such key terms in proposed subsection (j) as "market power abuse," "persistent market power," and "worked as intended" seem undefined, and recommended developing precise definitions for them.

In reply comments, STEC agreed with TIEC that it is premature to implement a safe-harbor provision. It recommended first allowing enough time to evaluate the effect of the rule's price protections.

TXU submitted comments on all three paragraphs in proposed subsection (j). In proposed paragraph (j)(1), TXU proposed replacing "lowest prices" with "highest prices," saying that the change addresses the improper and inefficient incentives created by paying a supplier the lower prices. TXU asserted that if a supplier is limited to the lower noncompetitive-constraint-mitigated price, it would have no incentive to supply power to the greater ERCOT market for a higher price, so that system-wide prices would tend to remain high. If, however, the supplier is limited to the system-wide mitigated price because it is lower than the noncompetitive-constraint-mitigated price, it is receiving less than what it really costs to clear congestion at that constraint.

Joint Commenters expressed agreement with TXU's rationale and its recommended change to proposed paragraph (j)(1).

In its reply comments, TIEC, after reiterating its view that implementing any safe-harbor provision is premature, opposed TXU's suggestion. It stated that if a safe-harbor provision is adopted, the mitigated price should be set at the lower of the system-wide cap and the mitigated price at the constraint. Because system-wide mitigation may be infrequent, TXU's proposal could result in a mitigated price that defaults to the $1,000/MWh system-wide cap in most intervals, even if CSM is adopted. Particularly for locations suffering from persistent congestion, that is an inappropriate result, TIEC asserted.

TXU proposed deleting the language "by an entity that did not have persistent market power" from proposed paragraph (j)(2). TXU stated that its recommended revision is based on the need for ex ante mitigation measures that offer safe harbor to all market participants, not just those lacking "persistent market power." It opined that properly designed ex-ante measures should lead to appropriate prices, thus making further disgorgement actions unnecessary. TXU further observed that the rule does not define "persistent market power," and that the commission still has not defined "market power." TXU contended that proposed paragraph (j)(2) fails to inform market participants of what conduct is needed to achieve the safe harbor, and hence risks being voided for vagueness in violation of the federal and state due-process clauses.

Joint Commenters, in their reply comments, supported TXU's recommended revision to proposed paragraph (j)(2).

TXU denounced proposed paragraph (j)(3) on several grounds. First, it stated that it would create significant regulatory and business uncertainty, and would be impossible to implement properly because it improperly assumes the ability to project an alternative market outcome (*e.g.*, ultimate prices had proposed subsections (h) and (i) "worked as intended"). Thus, some market participants would be paid too much, and others would be paid too little. Second, it declared that proposed paragraph (j)(3) is unconstitutionally retroactive, as it fails the three-pronged test required to render retroactive statutes constitutional. Specifically, TXU charged that this provision fails to advance the public interest; will defeat the reasonable expectations of market participants; and will cause unnecessary surprise to market participants that must rely on posted market-clearing prices in ERCOT-operated markets to manage risks and enter into bilateral contracts. To support its claim of unconstitutional, retroactive application, TXU cited an appellate court ruling prohibiting the commission from setting rates to allow a utility to recoup losses or to refund excess profits to consumers. Finally, TXU claimed that proposed subsection (j)(3) is unconstitutionally vague, especially because it encourages arbitrary and discriminatory enforcement, as the commission has not defined its intent for proposed subsections (h) and (i).

OPC disputed TXU's claim that proposed paragraph (j)(3) is unconstitutionally vague, asserting that the paragraph's regulatory goal is clear and its wording is not vague. OPC went further, stating that the limits that the provision imposes on the commission's enforcement authority are unnecessary. It recommended that proposed paragraph (j)(3) be revised to read as follows: "Notwithstanding this rule, the commission shall monitor market power. Market participants shall be subject to the investigatory and enforcement powers of the commission under PURA §39.157."

Like TXU, San Antonio recommended deleting paragraph (j)(3). It stated that proposed paragraph (h) and (i) contain mitigation mechanisms that will require further definition in the ERCOT Protocols. If an entity believes that these protocols fail to represent the intent or requirements of those subsections, it should challenge such protocols. Otherwise, San Antonio opined, the requirements of subsection (h) and (i) will, by definition, work as intended.

AEP averred that proposed subsection (j) does not necessarily provide a safe harbor against enforcement. It stated that the rule should be clear about the commission's intent in proposed subsections (i) and (j), so that the latter would be rendered moot; as an alternative, the commission should at least clarify whether proposed subsection (j) is intended to provide a safe harbor from further punitive actions (beyond profit disgorgement).

Like AEP, Brazos contended that proposed subsection (j) is not a true safe-harbor provision. It voiced fear that the application of the subsection will produce almost endless controversy and litigation, as the commission and suppliers dispute whether proposed subsections (h) and (i) work as intended.

Although it believed that including a safe-harbor provision in the rule is appropriate, BP expressed concern that the proposed provision includes terms that are insufficiently defined and could create significant uncertainty as to their application. As an example, BP cited the phrase "worked as intended" as potentially leading to subjective, after-the-fact evaluations of a market participant's offers. It also voiced concerns involving the lack of a definition of "persistent market power," and how a market participant with non-persistent market power could become aware of its status. Accordingly, BP suggested that the commission delineate as clearly as possible, with reference to the code-of-conduct rulemaking, what types of conduct would come under the safe-harbor provision, leaving room for participants to submit offers that reflect scarcity and other legitimate economic costs. Finally, BP opined that a well designed market-power mitigation plan itself would constitute a safe harbor.

DFW Coalition stated that restitution is not an adequate deterrent to market-power abuse, and expressed concern that such consumer safeguards as the ability to file a federal antitrust case could be removed. In the absence of such recourse, DFW Coalition suggested the ability to impose triple damages and a methodology for refunding monies to load-serving entities and their customers.

In their reply comments, Joint Commenters urged rejection of DFW Coalition's recommendation. They claimed that the commission lacks authority to award damages. They further stated that PURA §39.157(a) refers to its not affecting application of state and federal antitrust laws, and that PURA §15.032 makes clear that penalties accumulated under PURA are cumulative of any other penalty.

DFW Coalition agreed with Joint Commenters that the commission lacks authority to award damages, but stated that they saw no reason to provide a safe harbor to violators. To buttress this resistance to a safe-harbor provision, the Joint Commenters reported that victims of market abuse now lack remedies once available under federal and state antitrust law, due to courts' common invocation of the "filed-rate doctrine" which, in the view of Joint Commenters, provides a shield for regulated firms against antitrust claims. As an example, they cited the June 24, 2004 dismissal by the federal 5th Circuit district court of the case, *Texas Commercial Energy v. TXU Energy, Inc., et al.* (U.S. District Court - Southern District of Texas (Corpus Christi), Cause No. 03-CV-249).

Commission response

Proposed subsection (j) was dependent on the adoption of comprehensive price mitigation procedures. With the deletion of CSM, that will not occur in this rule. Therefore, the commission has deleted the subsection. The commission has also added a sentence to subsection (b) to make clear that the rule does not limit the commission's authority to ensure reasonable ancillary energy and capacity service prices and to address market power abuse.

Issue 6: Disgorgement of Windfall

Subsection (f) establishes a means by which the commission can correct any misallocation of costs or payments caused by flaws in ERCOT procedures. Please comment on the appropriateness of this subsection.

Brazos, DFW Coalition, OPC, STEC, TCE, and TIEC generally supported proposed subsection (f), while AEP, Austin Energy, AEP, BP, Joint Commenters, Reliant, Texas Genco, and TXU generally opposed it.

AEP, Austin Energy, Joint Commenters, Reliant, San Antonio, and TXU stated that the subsection would have a detrimental effect on the markets by increasing regulatory uncertainty. AEP, Texas Genco, and Joint Commenters stated that the regulatory uncertainty would discourage participation in the markets. Joint Commenters stated that the regulatory uncertainty would impose high risk premiums and raise prices. Reliant stated that the subsection would discourage loads from acting as resources by creating uncertainty in payment, and would affect REPs that have structured retail products based on the MCPE. Joint Commenters also expressed concern about the effects on market participants' certifications of their financial statements. Joint Commenters stated that the uncertainty created by the subsection would be substantially greater than the resettlements currently made by ERCOT, because the bases for such resettlements are addressed in the ERCOT Protocols.

TIEC stated that proposed subsection (f) is consistent with the commission's regulatory oversight of ERCOT. In contrast, Reliant stated that the subsection is beyond the commission's authority in PURA §39.157, which limits the remedies for market power abuse; the commission does not have the authority to require disgorgement of profits. Joint Commenters stated that market participants are required by PURA §39.151(j) to comply with ERCOT requirements, and PURA provides no authority for the commission to restate ERCOT requirements after the fact. Joint Commenters stated that the commission has no refund authority based on the commission's after-the-fact determination of what ERCOT procedures should have been.

Joint Commenters and TXU stated that proposed subsection (f) is unconstitutional because it is too vague. Joint Commenters also argued that subsection (f) is unconstitutional because it is retroactive.

Austin Energy, BP, Brazos, Joint Commenters, Reliant, San Antonio, and TXU stated that proposed subsection (f) is too vague. BP and San Antonio stated that the subsection should be either struck or precisely defined. Joint Commenters stated that a preferable procedure would be for ERCOT or the IMM to issue new rules that would apply prospectively, potentially on short notice like, for example, PJM does. BP stated that price adjustments because of a perceived flaw in the protocols or market design should be addressed expeditiously through an administrative process but prospectively only. TXU stated that a refund should be limited to a period beginning 60 days after the request for the refund is made, consistent with FERC's authority. TIEC opposed making a commission finding of a flaw in an ERCOT procedure prospective only, and stated that merely correcting the mistake without some sort of refund would not compensate consumers for their losses resulting from ERCOT's original error.

BP stated that clerical, administrative, programming, and data input errors might be properly subject to refunds or surcharges. TXU recommended replacing "flaw in ERCOT's procedures" with "market implementation error" and "emergency system condition." TXU defined a "market implementation error" as a "software flaw resulting in prices or payments that are inconsistent with ERCOT's procedures;" and an "emergency system condition" as "a situation in which a systematic equipment malfunction, including telecommunications, hardware, or software failures, prevents ERCOT from operating ERCOT-administered markets in accordance with ERCOT procedures, or where widespread electronic transmission or generation equipment outages prevent ERCOT from dispatching the system in accordance with ERCOT procedures." TXU stated that it believes that the definition of market implementation error would cover the high congestion costs experienced on the Farmersville-to-Royce transmission line in June and July 2003.

Reliant stated that FERC has rejected the “make the market whole” approach in proposed subsection (f), and instead limits the applicability of potential disgorgement of profits by considering any such action on a transaction-by-transaction basis. TXU stated that its proposal was consistent with the limited authority that FERC has granted the New York Independent System Operator (NYISO), PJM, and the Independent System Operator – New England (ISO-NE) to implement price corrections and resulting disgorgement. According to TXU, FERC has made it very clear that for markets that have moved beyond initial start-up, the limit of such price correction authority should be for “software implementation problems” or “emergency system conditions,” with all other “market flaws” requiring amendments of the market rules, instead of price corrections. TXU stated that at the inception of the NYISO market in September 1999, FERC approved the request of NYISO to implement “Temporary Extraordinary Procedures” (TEP) that allowed NYISO for the next 90 days to correct prices that were the result of “market design flaws” or “transitional abnormalities.” “Market design flaws” were defined as a “market structure, market design, or an implementation flaw which would result in market outcomes that would not be produced in a workably competitive market.” A “transitional abnormality” was defined as “a situation in which systematic equipment malfunctions, including telecommunications failures or widespread and massive transmission or equipment outages, prevents the dispatch of the system as intended by market rules.” The NYISO TEP stated that market design flaws and transitional abnormalities did not include situations in which “market outcomes are the product of relative scarcity or surplus.” For market start-up purposes, FERC extended NYISO’s TEP authority until October 25, 2001, when FERC ruled that such broad authority was no longer appropriate for a working market. TXU stated that, at the very least, the commission should place a time-limit on how long it will exercise broad refund authority.

Joint Commenters stated that the rule would permit refunds years after the fact, which would damage market participants' incentives to clarify or amend ERCOT's procedures. Joint Commenters stated that if the proposed approach is adopted, the deadline to initiate a proceeding should be 90 days from the relevant event, and the commission should process the proceeding in 90 days. TXU stated that if the commission adopted a refund period that follows the filing date of the corresponding refund request, the deadline for such a request should be 30 days after the occurrence complained of; and the refund proceeding should be limited to a 90-day timeframe. TXU stated that a 30-day deadline to file a refund request was reasonable, because under ERCOT's settlement system, market participants receive initial settlement statements 17 days after the operating day.

Texas Genco and Joint Commenters stated that any reallocation of funds should be limited to the purposes and processes addressed in existing ERCOT procedures. TIEC stated that the rule should clarify that the process leading to a commission enforcement action should be complaint-driven, and should be initiated after the aggrieved entity has utilized the dispute resolution procedures available to ERCOT. STEC stated that ERCOT should also have the power to refund or surcharge to remedy flaws without commission action. Brazos, ERCOT, and OPC recommended that details of the procedure be added.

TCE argued that the commission's authority to order refunds should be expanded; refunds should not be limited to non-compliance with the intent of the ERCOT Protocols.

Commission response

The commission has deleted proposed subsection (f) from the rule. At this time, the commission intends to continue to address market design flaws and other flaws in ERCOT procedures on a case-by-case basis. The commission notes that, although an entity must ordinarily exhaust ERCOT processes before bringing a complaint concerning ERCOT procedures to the commission, P.U.C. Procedural Rule §22.251(c) does provide circumstances where those processes can be bypassed, and also provides that the commission staff and OPC have the right to bypass those processes in all circumstances. Thus, P.U.C. Procedural Rule §22.251 provides affected entities and the commission with the flexibility to act quickly to resolve major flaws in ERCOT procedures, if such flaws cannot be quickly and adequately resolved by ERCOT.

At this time, the commission intends to continue to consider on a case-by-case basis whether retroactive relief should be granted in addition to prospective relief. The spike in local congestion costs related to the Farmersville-to-Royse transmission line during May through July 2003 is an example of an occurrence where the plain language of the ERCOT Protocols appeared to have conflicted with the intent of the Protocols. Before May 2002, ERCOT issued out-of-merit-order instructions to non-offered generation resources (*i.e.*, generation resources for which an offer premium of $0/MWh was submitted to indicate that the generation entities did not want the resources to be deployed to clear local congestion) without knowledge of the flexibility of the resources to move up or down or the associated costs. In response to complaints concerning resources not easily moved up or

down such as baseload resources and combined-cycle resources, ERCOT suggested in a market bulletin that resource entities offer in a manner that would indicate their resources' flexibility for being deployed for local balancing energy. Market Bulletin #6, issued by ERCOT in May 2002, indicated that a resource-specific premium of a high level (close to $999/MWh) would make it less likely that a resource would be instructed up, and that a very low offer ($-999/MWh) would make it less likely that a resource would be instructed down. Thus, the offer premium could be used to indicate that a resource entity did not want its resource to be moved. However, in a case where ERCOT had to issue an instruction for the resource to move anyway for reliability reasons, the offer premium was also used for settlement purposes if a Market Solution existed.

In late May 2003, Coral Energy began scheduling energy from the new Kiamichi resource into the ERCOT grid in northeast Texas. At about the same time, the Farmersville-to-Royse transmission line began experiencing frequent congestion. With four independent resources able to clear the congestion on the line and no particular resource essential for clearing the congestion, the definition of Market Solution was met. Resources belonging to Coral, FPL, the City of Garland, and TXU were deployed by ERCOT to resolve the congestion, and were settled on the basis of their offer premiums rather than at generic costs, because when a Market Solution existed, it was assumed that generation entities would offer competitively. However, three of the four resource entities involved continued to submit maximum offer premiums to indicate their desire not to be moved. This situation continued for 21 days in June and on July 1st, during which time the amount of payments to the four resource entities reached close to $60 million. ERCOT corrected the

market design flaw on a prospective basis, and commission staff reached settlements that provided for refunds of excessive payments to the generation entities to resolve the congestion, and no commission action was necessary. However, in the future, the commission may be called on to quickly resolve market design flaws and, as noted above, has the procedural flexibility to do so.

Issue 7: Reliability-Must-Run (RMR) Resources

Subsection (g) is intended to ensure that a generation resource that ERCOT has determined is required for reliability remains in operation. In addition, it is intended to provide an orderly process to resolve a dispute between the supplier and ERCOT that prevents the signing of an RMR agreement. Finally, it is intended to ensure that the supplier receives reasonable compensation for providing RMR service. This issue was discussed in ERCOT's RMR Task Force and Protocol Revision Subcommittee in the context of Protocol Revision Request 507, but no consensus was achieved. A generation resource that ERCOT has determined is required for reliability has market power, because ERCOT must take the steps that are necessary to ensure that the generation resource remains in operation. This situation gives the generation resource owner bargaining power to demand excessive compensation from ERCOT to provide RMR service. Consequently, price protections are needed. The commission is addressing this issue at this time because ensuring that reliability is maintained is essential; addressing the issue involves the creation of wholesale price protections, which is the primary subject of this rule; the proposed subsection involves action taken by the commission; and there is considerable *disagreement among Staff and a number of stakeholders concerning resolution of the issue. Please comment on the appropriateness of this subsection.*

ARM, DFW Coalition, OPC, STEC, and TIEC supported proposed subsection (g). Austin Energy's comments on the subsection were limited to a statement that it supported the language recently approved by the ERCOT Board in Protocol Revision Request (PRR) 507. The remaining commenters offered specific suggestions concerning the subsection. The main issues raised in comments concerned the determination of proper compensation; whether the generation entity should solely have the burden of filing; and whether PRR 507 sufficiently addressed the issues covered by the subsection.

a. Proper Compensation

Several commenters made specific proposals concerning the standard that the commission should use to determine compensation to a generation entity if ERCOT determines that its generation resource is needed for reliability. Joint Commenters suggested that opportunity costs should be the standard for compensation. ARM suggested that compensation should include fixed and variable costs and a reasonable profit. TIEC proposed compensation for both the reservation and the deployment of an RMR resource. The reservation payment, according to TIEC, should not exceed the verifiable cost of maintaining the unit, plus a reasonable fixed adder, and a deployment payment should not exceed the verifiable, short-run variable cost plus a fixed adder. According to TIEC, setting these maximum levels of compensation sets a standard for negotiations and assures that compensation will be cost-based. TIEC further argued that cost is the appropriate basis, because RMR resources possess local market power that must be mitigated to protect consumers. Texas Genco joined TIEC in noting that RMR is a regulatory rather than a competitive matter.

Brazos expressed concern about the delay in compensation that will result while the commission resolves the complaint. Additionally, Brazos was concerned about how ERCOT would settle payments if compensation determined by the commission is made retroactive to the 91st day following the date that ERCOT receives a generation entity's notification of the suspension of operations.

Joint Commenters requested that any compensation ordered by the commission pursuant to a complaint under the subsection become effective only upon the expiration of any existing RMR agreement.

ERCOT stated that it does not object to a strong commission role in determining compensation.

Commission response

The commission will not set specific compensation guidelines in this rule. Instead, the commission will address compensation disputes on a case-by-case basis, although it may institute a separate rulemaking at a later date to address this issue. The commission notes that the ERCOT Protocols contain compensation guidelines, and no entity challenged those guidelines within 35 days of their approval, pursuant to P.U.C. Procedural Rule §22.251(d).

The commission generally agrees with Joint Commenters that proposed subsection (g) is not meant to terminate any RMR agreement in force on the 91st day after ERCOT's receipt of a generation entity's notice. The commission, however, is authorized by PURA to review whether an existing RMR agreement remains in the public interest. In the event that the commission determines an existing RMR agreement is inconsistent with public policy, the commission could order offsetting or supplementing compensation to run concurrently with the term of the existing agreement, or other such compensation or terms. Accordingly, the commission amends proposed subsection (g) to clarify that the commission's ordered compensation becomes effective upon the expiration of any pre-existing RMR agreement, provided that the existing agreement continues to be in the public interest.

In response to Brazos' concerns about delay in receiving compensation pending a commission decision, the commission acknowledges that, absent settlement of a compensation dispute, there will be litigation delay. However, Brazos did not explain how the delay is harmful and did not propose any alternatives. The generation entity will receive compensation for out-of-merit-order dispatch during the pendency of the dispute, which compensates the entity for incremental costs plus a premium. *See* Protocols §6.8.2. The commission has clarified the part of proposed subsection (g) concerning availability for out-of-merit-order dispatch instruction. If Brazos' concern is the lost time-value of money, then a complainant can request compensation for such loss. As to Brazos' concern about ERCOT's settlement resulting from the commission's retroactive award of RMR

compensation, the commission notes that ERCOT has resettled on numerous occasions and the commission has no reason to believe that resettlement for RMR compensation would pose any unusual concerns.

b. Burden of Filing and Burden of Proof on Appropriate Compensation

Proposed subsection (g) places the burden of filing the complaint on the generation entity. The subsection does not expressly assign the burden of proof on the issue of compensation. By requiring the generation entity to take the role of the complainant, however, by implication the subsection assigns the burden of production and the burden of persuasion (together, the burden of proof) to the generation entity.

Joint Commenters suggested that either party — the generation entity or ERCOT — should be permitted to file the complaint with the commission. They claimed that the requirement that the generation entity file the complaint might improperly result in the generation entity being assigned the burden of persuasion (as opposed to the burden to go forward by producing information that the commission might need to make its decision). Joint Commenters claimed that there is no basis for allocating the burden of persuasion to the generation entity and that there is no basis for the assumption that the generation entity has a stronger bargaining position.

TXU suggested that the subsection should place the burden of proof on ERCOT, because it is ERCOT that claims the need for the RMR services; as written, the rule puts ERCOT in a superior bargaining position; and requiring ERCOT to carry the burden of proof will appropriately balance the bargaining power between generation entities and ERCOT. Joint Commenters generally agreed with TXU that the commission has no basis to assume that ERCOT will make fair and reasonable offers or that the generation entity has a stronger bargaining position. In support of this claim, Joint Commenters stated that with respect to RMR services, ERCOT is a monopsonist.

Commission response

The commission finds that the generation entity should bear the burden of filing the complaint with the commission, and the burden of proving the proper level of compensation or any other issue in dispute. The commission has amended the subsection to explicitly assign the burden of proof to the generation entity. As a matter of policy, ERCOT is entitled to the presumption that its determination of the need and compensation for RMR service is correct. ERCOT has a statutory duty to ensure the reliability of the ERCOT network. Determining the need for RMR service is an integral part of this responsibility. In addition, the commission previously certified ERCOT as the independent organization for the ERCOT power region, pursuant to PURA §39.151(a) and (c). ***Application of the ERCOT ISO for Certification as an Independent Organization to Perform Transmission and Distribution Access, Reliability, Information Exchange, and Settlement Functions,*** **Docket Number 22061, Final Order (Feb. 2, 2001). Therefore, pursuant to PURA §39.151(b), ERCOT has been found by the commission to be sufficiently independent of any producer or seller of electricity that its decisions will not be unduly influenced by any producer or seller. Furthermore, ERCOT has no financial incentive to**

underprice RMR service, because it allocates all costs and revenues from RMR contracts to market participants.

In response to TXU's and Joint Commenters' concerns about being disadvantaged in the RMR service determination process, the commission has amended proposed subsection (g) to make explicit that a complaint filed against ERCOT may include any issue pertaining to RMR service. In addition, pursuant to §22.251(f), the commission has amended proposed subsection (f) to require ERCOT to file a response to the generation entity's complaint and include as part of the response all existing, non-privileged documents that support ERCOT's position on the issues identified by the generation entity pursuant to §22.251(d)(1)(C).

c. PRR 507

Austin Energy, Joint Commenters, and Texas Genco supported the recently approved PRR 507 concerning RMR, and generally asserted that PRR 507 already resolves the issues addressed in proposed subsection (g). Joint Commenters also suggested that the subsection should require a generation entity to provide RMR services no longer than nine months after submission of notice to cease operations.

Commission response

The above commenters failed to acknowledge that PRR 507 is insufficient to ensure the reliability of the ERCOT network. Under PRR 507, if negotiations fail between ERCOT and a generation entity, the generation entity may cease operations even though ERCOT needs the RMR resource to continue operation in order to ensure the reliability of the network. The commission also rejects, for the same reason, Joint Commenters' suggestion to limit any commission-ordered RMR agreement to nine months from the initial notice. Again, the generation entity would be free to cease operation despite ERCOT's continued need for the RMR resource. The commission finds that proposed subsection (g) is necessary to ensure that ERCOT will have the generation resources that it needs to ensure reliability.

d. Authority

ERCOT requested identification and clarification of the source or sources of the commission's and ERCOT's authority to require a generation entity to provide service when needed for reliability.

Commission response

The primary statutory authority for ERCOT and the commission to require a generation entity to provide service when needed for reliability is PURA §39.151. This section

requires ERCOT to ensure reliability of the ERCOT network, and gives the commission oversight and review authority over ERCOT's implementation of this requirement.

e. Other Issues

Both AEP and Brazos requested clarification that a generation entity is not required to use the ERCOT alternative dispute resolution (ADR) process before filing a complaint with the commission under proposed subsection (g). In addition, Brazos and ERCOT questioned the use of the term "supplier" in the subsection. ERCOT proposed using the term, "generation resource owner" instead of "supplier," which is more consistent with the terms used in the ERCOT Protocols.

Brazos asked for clarification on the use and meaning of specific terms in proposed section (g). Brazos requested whether the use of the term "day," referred to calendar days, business days, or market days. Brazos also requested clarification of the use of the term, "finalized," in the phrase, "If, after 90 days following ERCOT's receipt of the supplier's notice, ERCOT and the supplier have not finalized a reliability must run (RMR) agreement .…"

Joint Commenters suggested changing proposed subsection (g) so that a generation entity can transfer a RMR resource to an entity that does not have a Resource Agreement with ERCOT as part of a merger with or acquisition of the generation entity owning the RMR resource. The amendment, Joint Commenters suggested, would prevent unnecessary cost, uncertainty, and delay. ERCOT proposed to substitute in the rule its description of the procedure for transferring a generation resource that may be required for RMR.

BP stated its support for efforts to reinforce the reliability of the ERCOT network. However, it suggested that the most appropriate way to address the RMR issues is in a standard generation interconnect agreement. BP claimed that this will “permit ERCOT and generation owners to better tailor their expectations, reach appropriate RMR service agreements more efficiently, and ensure that resources necessary for reliability purposes will continue to be available.”

Commission response

It is not the commission’s intent to require any generation entity filing a complaint with the commission under proposed subsection (g) to go through ERCOT’s ADR process before filing a complaint, because under the ERCOT Protocols, the 90-day notice period is intended to provide ERCOT an opportunity to determine whether the generation resource is need for reliability and, if it is, to negotiate an RMR contract with the generation entity. The commission also agrees that it is not clear from the proposed subsection (g) that ERCOT ADR is not required. Therefore, the commission agrees with AEP and Brazos and amends proposed subsection (g) as suggested. The commission has also replaced the term “supplier” with “generation entity,” and defined this term as well as “resource” and “resource entity.” Furthermore, the commission has split proposed subsection (g) into subparts to improve its readability. The commission has also made explicit that, unless otherwise ordered by the commission, the implementation of an RMR exit strategy

pursuant to ERCOT protocols is not affected by the filing of a complaint pursuant to proposed subsection (g).

For clarity, the term "day" has been replaced with "calendar day." The term, "finalized" was intended to mean that negotiations have concluded and a binding agreement has been signed. The reference to "finalized" has been replaced with a reference to "signed." In response to ERCOT and Joint Commenters, the commission has amended the subsection to ensure an easy process to transfer a generation resource, but that also ensures that the requirements of the subsection cannot be evaded through transfers.

The commission agrees with BP that some RMR issues could be addressed in a standard interconnection agreement, provided that the terms of the agreement do not conflict with the requirements of proposed subsection (g). A commission rule is necessary in the event no agreement can be reached between a generation entity and ERCOT. Accordingly, the commission declines to amend the subsection in response to the comments by BP.

Joint Commenters also claimed the following points:

> The subsection violates the Texas Constitution's prohibition against the impairment of contract. They also alleged that this provision is a "taking," and that the restrictions on the use of a RMR resource belonging to a generation entity are not justified. Texas Genco agreed that the rule creates a potential unconstitutional taking of assets.

> The subsection is contrary to PURA §39.109. PURA §39.109 requires the owners of generation facilities transferred prior to the start of competition to maintain the same operating personnel for two years after the transfer to ensure the continued safe and reliable operation of the facility.

> The generation entity would be required to maintain the availability of the resource without ERCOT or commission analysis of the circumstances. They claimed that the generation entity would have to maintain availability even if it were no longer able to make the required representations found in the form RMR Agreement, or if the unit could no longer be operated safely or in conformance with environmental laws.

> The subsection "places responsibility for reliability solely and permanently on the individual supplier" for reasons beyond the control or expectations of the supplier, and that this would be unfair and disincent market entry.

> The time limits in the subsection are all one-sided against the generation entity and the requirement that the generation entity file the complaint is also one-sided and artificial.

In addition, Joint Commenters and Texas Genco claimed that the subsection will not increase reliability, because a generating unit can fail at any time.

Commission response

Joint Commenters provided no explanation or analysis of how proposed subsection (g) violates the Texas Constitution, nor did they indicate which part of proposed subsection (g) causes the alleged infirmity. Similarly, Joint Commenters failed to provide an explanation of how the subsection is contrary to PURA §39.109. Although Joint Commenters set forth the language of the statute in their comments, they did not state what they believe the Legislature intended, nor did they explain how the subsection is "contrary to legislative intent." Joint Commenters also did not explain why any additional cost, uncertainty, or delay would be unnecessary. By ensuring the continued operation of RMR generation resources, the subsection avoids unacceptable risks to reliability, including blackouts. As a result, any resulting additional cost, uncertainty, or delay is necessary.

Joint Commenters are incorrect in their claim that a generation entity would have to maintain availability even if the resource could no longer be operated safely or in conformance with environmental laws. Protocols §5.4.4(2) provides that an entity does not have to comply with a dispatch instruction if such compliance would create a threat to safety, and nothing in this rule or in a RMR agreement resulting from implementation of this rule is meant to contradict that Protocol. In addition, Protocols §22(F)(13)(L), which is part of the standard form RMR agreement, provides that in the event of a conflict between the agreement and a law, the law shall prevail.

Joint Commenters are incorrect in their assertion that neither ERCOT nor the commission would review the individual circumstances. Joint Commenters appear to have expressed a concern about the generation entity's ability to maintain the availability of the resource during the pendency of the dispute. As discussed above in response to a comment by Brazos, the generation entity will receive compensation for out of merit order dispatch during the pendency of the dispute, which compensates the entity for incremental costs plus a premium. *See* Protocols §6.8.2. If that is insufficient to meet the cash flow requirements of the generation resource, the generation entity can enter into an interim RMR agreement with ERCOT or obtain interim relief from the commission. The commission has amended proposed subsection (g) to make explicit the right to seek interim relief from the commission, as well as the right to seek an expedited schedule and identify any special circumstances pertaining to the generation resource at issue.

Joint Commenters' characterization that responsibility for reliability would be placed "solely and permanently on the individual supplier," is inaccurate. Joint Commenters ignored the fact that other market participants will be paying for the RMR service. Therefore, it is more accurate to say that all market participants will share the responsibility of maintaining RMR service in ERCOT. Joint Commenters also claimed that the subsection will "disincent market entry." Although the duties under the subsection may impose exit restrictions on a generation entity at some point in the future, under the subsection, the generation entity will receive reasonable compensation. Furthermore, Joint Commenters fail to note the offsetting positive incentive to entry that

the operation of a more reliable network can offer a generation entity contemplating doing business in ERCOT.

Joint Commenters did not explain what they mean by "unfair" or "one-sided," nor did they explain how the time limit in the subsection, or the requirement that the generation entity file the complaint, is "one-sided." As discussed above, as the independent organization responsible for reliability of the network, it is appropriate to presume that ERCOT acted appropriately. Consequently, if there is a dispute, the generation entity should have the burden to complain to the commission.

Texas Genco essentially argued that ERCOT should not rely on RMR resources to ensure the reliable operation of the grid, because it is possible that a RMR resource could fail. Although this statement is true, it is also true that wires, transformers, and other transmission elements can fail. The reason for an RMR resource is to control the risks to reliability at an acceptable level.

Comments on Specific Sections of the Proposed Rule

Proposed Subsection (b), Applicability

Several parties recommended amendments to proposed subsection (b), which governs the applicability of the proposed rule. Brazos Electric suggested inserting the word "wholesale" into the first sentence of the subsection, such that the subsection would apply only to entities that buy or sell “at wholesale” energy, capacity, or any other wholesale electric service in a market operated by ERCOT. Joint Commenters and Reliant both proposed deleting from subsection (b), “Entities shall not circumvent the application of this section’s requirements through agreements or other forms of cooperation.” Joint Commenters contended that this sentence is unconstitutionally vague, and is in any event unnecessary, as the rule would apply to this conduct without it. Reliant similarly argued that this sentence is superfluous, because entities cannot circumvent the applicability of this rule through cooperation or agreement in any event, even without this sentence. Brazos asked whether examples could be provided of instances of “agreement” or “cooperation” in which entities attempted to circumvent the applicability of this rule.

Commission response

The commission agrees with Brazos that the addition of the word “wholesale” into the first sentence before the words “energy, capacity or any other wholesale electric service,” appropriately clarifies the commission’s intent that this rule apply only to wholesale transactions. The commission therefore has amended the rule accordingly. However, the commission declines to state, at this time, detailed examples of how entities might agree or cooperate towards the end of circumventing this rule, as suggested by Brazos. It is the commission’s intent that this rule apply to both the sole action of a market participant, and the collective action of more than one market participant. Describing examples of such conduct would be a hypothetical exercise only and many obvious examples could be

provided, such as joint conduct between market participants based on a written contract that provides for actions that are clearly in violation of the rule.

Likewise, the Joint Commenters and Reliant focused on the same sentence in proposed subsection (b), but unlike Brazos, these commenters recommended deleting the sentence entirely. The commission intends that this rule apply to entities both acting alone or in concert. Inclusion of this sentence emphasizes this point, even if the sentence is not necessary for application of the rule to group conduct. Furthermore, the commission concludes that this sentence is not impermissibly vague. Rather than define specific conduct that is within the rule, this sentence makes the more limited point that the rule will not be held inapplicable simply because the alleged conduct involves more than one market participant. On this basis, the commission believes that the intent of this sentence is helpful in reinforcing the scope of the rule. However, the commission does not believe that it is necessary to state this requirement in a separate sentence, as is the case with the proposed rule. As a result, the commission deletes the second sentence of proposed subsection (b) and amends the first sentence of the subsection to begin, "This section applies to any entity, either acting alone or in cooperation with others, that buys or sells …."

Proposed Subsection (c), Definitions

A number of commenters recommended modifications to the definitions set forth in this subsection that related to proposed subsection (i) and CSM. Brazos stated that additional terms may require definition, such as ERCOT system-wide offer cap, control, effective local resource capacity, and local load. Brazos also suggested several points of clarification on the definition of "competitive offers" in proposed paragraph (c)(2), including the definition of "total offers," the proper distinction between "offers" and "parties," and whether a pivotal supplier may make multiple offers. Brazos also queried whether the rule should consider offers by affiliates as one offer.

In the definition of "pivotal supplier," Brazos stated that "it" appeared to refer to ERCOT. If this is the proper reading, Brazos stated, then only suppliers selling to ERCOT can be considered pivotal suppliers. Brazos Electric questioned whether this limitation was intended.

Joint Commenters opposed including definitions for "competitive offers," "95th percentile price," and "pivotal suppliers," as all of these definitions pertaining only to proposed subsection (i) (CSM), which Joint Commenters oppose. TXU also proposed to delete these definitions, arguing that they are not required if the commission accepts its proposal to delete proposed subsection (i). If the commission were to adopt proposed subsection (i), however, TXU proposed an alternative definition of pivotal supplier that accounts for demonstrably inflexible capacity and capacity that is committed under long-term sale contracts, or is required to serve load under regulated prices.

Joint Commenters recommended adding "hockey stick pricing" as a defined term, and drew its definition from the preamble to the proposed rule. Joint Commenters asserted that this definition is needed to distinguish hockey stick pricing from other forms of bidding that pose no concern.

Joint Commenters proposed that the definition be stated as "Pricing that occurs when a supplier prices a small, economically expendable portion of its offer exorbitantly high."

Reliant recommended modifying the definition of "competitive offers" in proposed subsection (c)(2) to raise the percentage level at which a pivotal supplier may be considered to have made a competitive offer from 5.0% to 10%. Reliant suggested that the higher number is the equivalent of ten equally sized suppliers, and results in a Herfindahl-Hirschman Index (HHI) of 1,000, which is a more desirable level of competitiveness. In response, TIEC opposed Reliant's suggested amendment. In TIEC's view, HHI standards are not relevant if a supplier has already been determined to be pivotal. The 5.0% threshold permits pivotal suppliers only *de minimus* participation in the market before mitigation measures will apply, according to TIEC. If the threshold is increased, TIEC argued, a pivotal supplier might be able to make significant bids into the market and bid up prices while being immune from pricing safeguards.

Texas Genco recommended modifying the definition of "competitive offer" in proposed subsection (c)(2) to include those offers submitted by a pivotal supplier whose offers account for 15%, rather than 5.0% of the total offers.

Commission response

Withdrawal of CSM from this rulemaking for the reasons previously stated makes it unnecessary to define "competitive offers," "95th percentile price," and "pivotal supplier" at this time, and the commission has therefore deleted these definitions from the rule. The

commission declines to add a definition of "hockey stick pricing," as it also is primarily relevant to CSM.

Texas Genco recommended changes to the definitions of competitive and non-competitive constraints. Texas Genco suggested modifying the definition of competitive constraint such that the first sentence would read, "A transmission element on which no supplier possesses local market power with respect to the price of electricity at or near that element." In addition, Texas Genco suggested amending the definition of noncompetitive constraint to include only a transmission element on which a supplier possesses local market power with respect to the price of electricity at or near the element. TXU proposed several changes to the definitions of competitive and non-competitive constraints. TXU suggested modifying the definitions of competitive restraint and noncompetitive constraint such that they do not include the term "local market power," which is not yet defined by the commission. TXU stated, however, that it agreed with the meaning of this proposed definition. Joint Commenters agreed with TXU's proposed amendments to the definition of competitive constraint and noncompetitive constraint, because TXU's proposals deleted market power definition concepts, which would require further exploration in the rule.

ERCOT stated that a number of terms that appear throughout the rule should be defined terms. ERCOT suggested that the following terms be defined: local market power, supplier, virtual offer, total requirements, persistent market power, effective local resource capacity. Brazos stated that several terms used in proposed subsection (d) require definition, such as "market day," "virtual offers," and "market intervals."

Commission response

Proposed subsection (h) directs ERCOT to develop procedures to mitigate the effects of local market power caused by congestion, and part of this task is to specify a method by which noncompetitive constraints may be distinguished from competitive constraints. The commission believes that any refinement or interpretation of the definition of these terms (or terms contained within those terms) is appropriately undertaken in the stakeholder process required by proposed subsection (h). The commission does not wish to go beyond the basic definitions for those terms stated in the proposed rule before the process mandated by proposed subsection (h) has been completed. Nevertheless, the commission notes that the definition of local market power is the subject of another rulemaking project, Project Number 29042, making it inappropriate to define the term in this project. TXU's suggested revision to the definitions of competitive constraint and noncompetitive constraint to exclude "local market power" is reasonable, consistent with the commission's intent, and applicable to the work that has already taken place in the TNT process. The commission has therefore amended these two definitions accordingly.

The commission has also acted on Brazos' comments regarding a definition for "market intervals" as used in proposed paragraphs (d)(1) and (d)(2). The commission's intent was to reference ERCOT's settlement intervals. As a result, the commission has amended proposed paragraphs (d)(1) and (d)(2) to change the reference from market intervals to settlement intervals.

The commission notes that the term "effective local resource capacity" is a term defined immediately after it is used in proposed paragraph (k)(2), which states that "effective local resources capacity is the sum of each resource's capacity multiplied by its shift factor relative to the constraint." In any event, as discussed above, the commission has deleted proposed subsection (k).

Proposed Subsection (e), Control of Resources

ARM, in reply comments, observed that because the requirements of proposed subsections (d) and (e) do not impinge on the process of developing a nodal market, their inclusion in the rule is appropriate.

Joint Commenters recommended clarifying proposed subsection (e). They characterized as obscure the sentence, "A controlling entity has a substantial stake in the resource's profitable operation," and noted that the subsection does not address what happens if the definition of "controlling entity" seems to fit more than one entity, or if entities dispute who the controlling entity is. They also questioned why "a specified portion of a resource" was included in the next-to-last sentence. In addition, Joint Commenters observed that although the term "affiliate" is used in several places, the rule does not define the word. They stated that the definition in P.U.C. Substantive Rule §25.5 pertains to a utility affiliate, and hence does not fit precisely in this context. Joint Commenters further complained that the last sentence of the subsection increases potential confusion, and questioned why resources under common control would be considered affiliated for purposes of the subsection.

Reliant observed that the QSE may not be aware of the change in control of a resource prior to 14 days before the transfer. Consequently, it suggested inserting the following language after the second sentence in the subsection: "In the event the information is not known by the entity responsible for scheduling resources within the 14-day period, such notifications shall be made the earlier of the date on which the information is known or the date of the transfer of the control of the units." In their reply comments, Joint Commenters expressed support for Reliant's suggestion.

TIEC opined that although the subsection's definition of "control" is adequate for addressing resource control at the company level, the commission should focus not just on control by resource owners, but also should consider potential market abuse by QSEs. A resource-owning QSE can use its knowledge of offers and supply schedules to manipulate the market by adjusting its own offers or by colluding in bidding with other resource owners that schedule with the QSE. But even a non-resource-owning QSE can engage in manipulation strategies, TIEC contended, such as using information regarding offers and supply schedules of multiple resources with which the QSE has profit-sharing arrangements, perhaps even without the knowledge of the resource owners.

Texas Genco criticized the first sentence of the subsection as vague, and asked what kind of proof will be required to verify control of a resource.

TXU proposed modifying the subsection to read as follows:

> (e) Control of resources. An entity registered as a resource with ERCOT shall inform ERCOT as to who controls the resource, and provide proof that is sufficient for ERCOT to verify control. In addition, any entity registered as a resource with ERCOT shall notify ERCOT of any change in control of the resource no later than seven business days after the date that the change in control takes effect. For purposes of this section, "control" means ultimate decision-making authority over how a resource is dispatched and priced, either by virtue of ownership or agreement, and a substantial financial stake in the resource's profitable operation. Any resource or specified portion of a resource shall be considered to have only one controlling entity. Resources under common control shall be considered affiliated.

TXU stated that the substituted wording for the "responsible for scheduling" language in the first sentence addresses the fact that QSEs are often not contractually privy to the detailed control structure of the resources that they represent; therefore, resource entities should be required to report their own control structure to ERCOT. TXU stated that its proposed timing change regarding notification of change in control is consistent with ERCOT Protocol §16.5.3. According to TXU, this change would still allow the commission's Market Oversight Division (MOD) and the IMM to monitor the exact point at which control was passed, but would avoid negative financial effects on market participants in situations where changes in control occur due to defaulting contractual parties. TXU reported that its substitution of the phrase "dispatched and priced" for "scheduled" is intended to comport proposed subsection (e) with the Texas Nodal structure, as well as with Federal Trade Commission and Department of Justice analyses of "control." Finally, TXU stated that its final change to the subsection recognizes the reality that a QSE must have a significant financial stake in the profitable operation of the resource to be considered an affiliate; merely representing a resource is insufficient to consider the QSE an affiliate of the resource. In reply comments, Joint Commenters supported TXU's recommended revisions to proposed subsection (e), as well as TXU's justifications for them.

Commission response

Concerning Texas Genco's comment about what proof is required to establish control of a resource, that detail is best left for ERCOT to address, because it is the entity that will need to determine control. The commission has also substantially accepted TXU's suggested language on the meaning of "control." In addition, in response to Joint Commenters' statements about joint control, the commission has deleted the requirement that a resource be considered to have only one controlling entity, and has added a requirement to inform ERCOT of the right to use of an identified portion of the capacity of a jointly controlled resource. TIEC's comments about the potential for market abuse by QSEs apart from the control of resources, are beyond the scope of the subsection, which is limited to ascertaining the entities that control resources.

The commission acknowledges that the scheduling entity may lack the timely knowledge needed to comply with the requirement for advance notice of change in resource control.

Substituting "resource entity" for "entity responsible for scheduling resources with ERCOT" eliminates this problem. In any event, advance notice of change in control is essential to effective market monitoring, as it alerts MOD to possible changes in market participant conduct and helps MOD quickly address any concerns that consequently arise. In addition, advance notice to ERCOT of changes in control may be necessary for use in the application of ex-ante price mitigation measures, to allow ERCOT sufficient time to reflect the changes in the ex-ante measures before they are applied to the periods after the changes in control occur. As to TXU's concern about a resource entity that obtains control of a resource due to its counterparty's default, the commission has added a provision that allows for notice as soon as possible in the event that the general notice deadline cannot be met.

Given the definition of "control" and the context provided by the rest of the amended subsection, the commission considers the meaning of "affiliate" to be clear.

Proposed Subsection (h), Local Market Power

Proposed subsection (h) provides that ERCOT, through its stakeholder process, shall develop and submit for commission approval procedures to mitigate the effects of local market power caused by congestion. Such procedures will specify a method by which noncompetitive constraints may be distinguished from competitive constraints. Brazos requested a clarification as to whether the referred procedures should be part of the protocols or part of the substantive rule.

Reliant suggested language change in proposed paragraphs (h)(1) and (h)(3) to clarify that ERCOT stakeholders should develop “protocols” rather than “procedures” to mitigate the effect of local market power, and that these protocols “shall be designed to ensure” rather than “shall ensure” that a noncompetitive constraint will not be treated as a competitive constraint.

In proposed paragraph (h)(2), Reliant wanted to specify that the designation of local constraints should be reviewed monthly, and that a constraint should be re-designated if it meets well defined criteria to show a change in the competitiveness from the annual designation. Reliant suggested deleting the proposed requirement for monthly criteria more stringent than the annual criteria on the grounds that this level of detail is unnecessary, and that it would make subsequent changes in the methodology difficult.

In proposed paragraph (h)(4), Reliant suggested that the “protocols,” rather than the “procedures,” be submitted to the commission for approval, and that subsequent changes to the protocols need not be submitted to the commission for formal approval, but instead should proceed through the Protocol revision process established in the Protocols. San Antonio concurred. TXU suggested deleting this entire subsection, stating that the Protocols, including protocols addressing noncompetitive constraints, are already required to be submitted to the commission for approval, and that the commission already has the authority to approve or reject future changes in the Protocols.

In reply comments, STEC disagreed with Reliant, San Antonio, and TXU, stating that it is critical that the procedures adopted by ERCOT through the stakeholder process be submitted to the commission for approval.

Brazos and ERCOT suggested that there should be a definition of “local market power.” TXU suggested changing references to “local market power” to references to “noncompetitive constraints,” and changing the subsection’s title from “Local Market Power” to “Noncompetitive Constraints,” stating that “local market power” is not defined in the proposed rule, and that “market power” is not defined anywhere by the commission. In reply comments, Joint Commenters proposed changes to the definitions for competitive constraint and noncompetitive constraint that would eliminate the reference to a “supplier who possesses local market power with respect to the price of electricity” and more simply define a competitive constraint as “a transmission element on which prices to relieve the constraint are moderated by the normal forces of competition between multiple, unaffiliated resources,” while in the definition of a noncompetitive constraint, prices to relieve the constraint are not moderated by such forces.

In reply comments, Joint Commenters expressed a concern about proposals to define certain key terms by several commenters without a proposal for a definition that others can address in reply comments.

TXU suggested specifying that competitive and noncompetitive constraints should be designated one month prior to the annual auction of CRRs. In proposed paragraph (h)(3), TXU suggested simplifying the language to refer to "mitigation procedures" rather than to "procedures for mitigating local market power."

TIEC objected to proposed paragraph (h)(2) for prejudging certain aspects of the ERCOT process, and suggested deferring consideration of all aspects of ERCOT's local market power mitigation proposal to November 1. TIEC wanted to delete the entire subsection.

Joint Commenters suggested specifying that the procedures to be developed by ERCOT should provide for recovery of verifiable costs and an adder, which together would provide recovery of total costs including capital costs and a return of and on investment.

In reply comments, TIEC objected to the proposals by Reliant and Joint Commenters to incorporate details regarding local market power mitigation into the current draft rule, stating that such proposals are premature and should be raised in the ERCOT process. TIEC objected in particular to Joint Commenters' proposal that would guarantee that generators recover their long term operating costs, stating that cost recovery guarantees are inappropriate in competitive markets.

Commission response

The commission has changed "procedures" to "protocols," for two reasons. First, use of the term "protocols" is consistent with ERCOT's longstanding use of that term. Under ERCOT Protocols §1.1, the ERCOT Protocols "mean the document adopted by ERCOT,

including any attachments or exhibits referenced in these Protocols, as amended from time to time that contain the scheduling, operating, planning, reliability, and settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT." Second, using the more specific term "protocols" recognizes that ERCOT need not obtain commission oversight and review for detailed implementation procedures related to mitigation of noncompetitive constraints. In addition, the commission changed references to "approval" to "oversight and review," because the latter language is most consistent with the language in PURA §39.151(d) and the commission's recent modifications to P.U.C. Substantive Rule §25.501.

Under P.U.C. Procedural Rule §22.251, an affected entity may challenge ERCOT's adoption or amendment of a protocol. This process is appropriate for the large majority of protocols, because they concern detailed operational issues for which stakeholders usually share common interests. In contrast, mitigation protocols directly affect resource entities' profitability, and their short-term financial interests are directly in conflict with the entities that will be required to pay for the ancillary services that the resource entities provide ERCOT in order to manage the congestion on the noncompetitive constraints. In addition, mitigation protocols that address noncompetitive constraints have significant effects on the long-run viability of the ERCOT wholesale market, because the mitigation protocols affect the availability and siting of resources. Consequently, in proposed subsection (h), the commission has required that both new protocols and protocol amendments concerning mitigation for noncompetitive constraints be submitted to the commission for oversight and review. The commission has also amended the language of

the subsection to make clear that the protocols developed pursuant to the subsection shall be submitted to the commission as part of the implementation of the requirements of P.U.C. Substantive Rule §25.501, so that the protocols will take effect as part of the wholesale market design required by that rule.

The commission agrees with Reliant's proposal to change "shall ensure…" to "shall be designed to ensure…," in order to recognize that mitigation protocols do not always work as intended.

The commission agrees with TIEC in reply comments that certain details are not necessary in the rule, and should first be addressed through the ERCOT stakeholder process. Among these details are Reliant's proposal that the designation of local constraints should be reviewed monthly; TXU's proposal that competitive and noncompetitive constraints should be designated one month prior to the annual auction of CRRs; and Joint Commenters' proposal regarding cost recovery when mitigation is applied. Similarly, the commission agrees with Reliant that the requirement for more stringent monthly designation criteria than annual designation criteria brings an unnecessary level of detail into the rule, and therefore has deleted this requirement from the rule. However, the commission disagrees with TIEC that the entire subsection should be deleted. The commission believes that it is important for the commission to specify by rule that the protocols for designating noncompetitive constraints must be submitted to the commission for approval, and cannot be changed through the stakeholder process without commission approval.

The commission agrees that the term "local market power" is not defined, and has adopted TXU's proposal to change references to "local market power" to references to "noncompetitive constraints," and has changed the title of the subsection accordingly. The commission has also changed the definition of competitive constraints and noncompetitive constraints to eliminate reference to "local market power," as suggested by Joint Commenters.

Proposed Subsection (k), Congestion Revenue Rights

Austin Energy stated that it does not object to proposed subsection (k). In contrast, San Antonio, Texas Genco, and TXU recommended the deletion of proposed paragraph (k)(2). TXU proposed deleting paragraph (k)(2) because according to TXU, it is inconsistent with the operation of generating units in a load pocket. TXU averred that proposed paragraph (k)(2) might force the operation of older, less efficient units that might not otherwise operate. The key issue, according to TXU, is the withholding of units to enhance the value of CRRs, which the market monitor can prevent without formal ownership limits. TXU stated that if the commission decides to impose limits on CRR holdings, then the details should be specified in the Texas Nodal Protocols for review by the commission. TXU stated that the use of shift factors in proposed paragraph (k)(2) is improper without a specified withdrawal bus, and the paragraph has no clear definition of "local load."

San Antonio objected to limitations on CRR holdings, especially because CRR deration, as stated in proposed paragraph (k)(4), would reduce the potential for market power abuse by eliminating the DEC game. Texas Genco asserted that CRR limits reduce the liquidity of the CRR market to the detriment of those bearing the embedded cost of the transmission system. Texas Genco also asserted that CRR auction prices should fully reflect the expected value of the transmission congestion.

TXU stated that the broad requirements for any CRR derating should be inserted into P.U.C. Substantive Rule §25.501, with implementation details left for the Texas Nodal Protocols. TXU recommended revisions of proposed paragraphs (k)(3) and (k)(4) in order to provide consistency with the point-to-point CRR design of the Texas Nodal Protocols.

In proposed paragraph (k)(1), Brazos asked for a definition of “beneficiary,” “days,” and “market days.” In proposed paragraph (k)(2), Brazos asked what the difference in definitions was between “entity” and “supplier.” In proposed subsection (k)(3), Brazos asked for the definitions of the following terms: point-to-point option, point-to-point obligation, portfolios, source point, and sink point. In proposed paragraph (k)(4), Brazos asked how ERCOT would determine shadow prices. San Antonio asked for specific definitions of “shift factors” and “constraint,” as well as the context in which the commission defines them.

Commission response

The commission has deleted proposed subsection (k) in order to give ERCOT stakeholders the opportunity to address the issues in the subsection as they develop the Texas Nodal Protocols. The commission will again consider the issues addressed in the subsection as part of its review of the Texas Nodal Protocols after ERCOT has filed them with the commission.

Proposed Subsection (l), Independent Market Monitor

Reliant suggested adding language to ensure that information is kept confidential when the IMM communicates with MOD, and to clarify that the IMM must report to MOD once it has completed its communications with a market participant.

Brazos questioned whether the creation of an Independent Market Monitoring Committee (IMMC) comprising the independent Board members and the Director of MOD as an ex-officio non-voting member means that the IMMC would have special powers that the ERCOT Board as a whole could not oversee, and asked whether this would result in a potential breach of the Board's fiduciary duties.

The proposed subsection would allow the IMM to be staffed with either ERCOT employees or consultants. Brazos suggested that, in light of the issues that surfaced in the spring of 2004 regarding the use of consultants by ERCOT, there should be a more definitive rule on how to staff the IMM. Joint Commenters opposed the IMM being staffed with ERCOT employees. Furthermore, Joint Commenters would require barring from eligibility a person that has served as an officer, director, owner, employee, partner, or legal representative of ERCOT, or of a market participant operating in ERCOT, or of an entity that supplied at least $10,000 of products or services to ERCOT, during the two years preceding IMM appointment; or a person that owned or controlled stocks or bonds with a value of $10,000 or more in any of the referred entities. In addition, Joint Commenters would bar a person that has served the IMM from employment with any of the referred entities for one year after leaving IMM service.

Brazos suggested that the IMMC should be involved along with the IMM and MOD in developing policies to ensure appropriate integration of IMM and commission oversight of the ERCOT market. Brazos also suggested that the ERCOT Board be involved in developing screens and indices for the IMM to monitor, along with the screens and indices provided by MOD or created by the IMM. Regarding the requirement for the IMM to report unusual offers and bids or other questionable activities to MOD, Brazos asked for a clarification as to what is considered "unusual" and "questionable." Regarding the provision that the IMM shall discuss all identified instances of harmful behavior with commission staff and ERCOT legal staff, Brazos suggested that the IMMC should also be included in these discussions.

Texas Genco and Joint Commenters proposed to eliminate the requirement for the IMM to inform MOD of unusual offers and bids or other questionable activities before contacting market participants to investigate the issue.

OPC recommended the inclusion of the member of the ERCOT Board that represents OPC as a member of the IMMC. Regarding the requirement that the IMM produce a "State of the Market Report" assessing the competitiveness of the ERCOT-operated markets, OPC recommended a requirement that a general summary of the information described in proposed paragraph (l)(6), relating to all identified instances of harmful behavior that cannot be resolved informally, be included in the report.

TIEC supported the creation of an IMM for ERCOT as provided in the proposed subsection, and urged the commission to implement the IMM as soon as the second quarter of 2005, rather than delaying implementation until April 2006. TIEC suggested two changes to the proposed subsection. First, TIEC recommended that the IMM be precluded from using ERCOT employees for its staff, in order to preserve the IMM's independence. This would not prevent the IMM from relying on ERCOT staff for support tasks. Second, TIEC recommended modifying proposed paragraph (l)(7) to clarify the timetable for the IMM reports, in order to ensure that the reports remain abreast of the changes in the ERCOT markets.

In reply comments, TIEC addressed Reliant's proposal that would require MOD to keep the IMM's findings of market abuse confidential. TIEC opined that, while there are good reasons to keep questionable market behavior confidential during an investigation, the investigation findings should be made public if it is found that market abuse occurred, in order to deter further abuses.

ERCOT supported the creation of an IMM as proposed.

The Joint Commenters recommended language to ensure that the IMM and commission staff coordinate in an effort to avoid duplicative or inconsistent requirements or proceedings. The Joint Commenters suggested adding a materiality standard to the provision that the IMM should discuss with the commission staff and with ERCOT legal staff identified instances of harmful behavior. In reply comments, Joint Commenters opposed OPC's proposal that the OPC member on the ERCOT Board be a voting member on the IMMC, stating that the IMMC would no longer be independent. In support of their position, Joint Commenters stated that OPC is not independent, because it has a statutory obligation to represent a particular market sector, and added that the legislature has not given OPC any oversight authority that would entitle it to special status of the type OPC sought.

In reply comments, STEC expressed concerns about the establishment of an IMM at ERCOT to monitor the real-time market, stating that ERCOT's reputation for discerning market abuses is dismal. STEC stated that consumers and small stakeholders had previously expressed a preference that real-time market monitoring be done by MOD, provided that sufficient financial resources be made available to MOD. STEC opined that the IMMC could not do as good a job as MOD. STEC added that the independent Board members could be influenced by the market stakeholders with whom they serve on the Board, and that an IMM at ERCOT may not restore consumer confidence in ERCOT or in a competitive market. At a minimum, STEC supported the inclusion of the representative from OPC on the ERCOT Board in the IMMC.

Commission response

The commission has deleted proposed subsection (l), because the issue of a market monitor will be considered by the Legislature in its upcoming session. Since the publication of the proposed rule, the Sunset Commission has made the following recommendations to the Legislature concerning market monitoring: (1) require ERCOT to contract with, fund, and support the operations of a private company to perform market monitoring; (2) require the commission to select the monitoring company, define the company's monitoring responsibilities, and set standards for funding, staff qualifications, and ethical conduct; (3) require the market monitoring company to report potential violations of commission or ERCOT rules or other potential market manipulations to the commission; and (4) require the market monitoring company to submit an annual report to the commission and ERCOT identifying market design flaws and recommending methods to fix the flaws. *Sunset Commission Decisions, Public Utility Commission of Texas* (September 2004) at 11-13. In response to a recommendation from a member of the public that the market monitor report directly to the three independent members of the ERCOT Board, the Sunset Commission staff responded that such a reporting structure may have the unintended consequence of tying the monitors too closely to the ERCOT Board. Sunset Commission staff instead recommended that the market monitor directly report to the three members of the commission. The Sunset Commission adopted this recommendation. In addition, the Sunset Commission Decisions report states that the monitoring staff would have unrestricted authority to communicate with commission staff. The commission supports the Sunset Commission's recommendations to the Legislature, and looks forward

to the discussion of market monitoring in the upcoming legislative session. The commission will reconsider a rule on this issue after the upcoming legislative session has ended.

Proposed Subsection (m)

CPS and the Joint Commenters suggested that the commission clarify which subsections are to be implemented under the current market design and which subsections are to be implemented as part of any future nodal market design. TIEC suggested that the following aspects of the rule should be implemented as soon as possible: CSM, expansion of disclosure requirements for resource offers, regulations pertaining to RMR resources, and the creation of an IMM.

Commission response

As a result of other amendments made to the proposed rule, the commission finds that subsection (m) is no longer necessary and therefore has deleted it. Only proposed subsection (h) is dependent on the new market design, and that subsection specifies its own implementation requirements. All other provisions of the rule shall become effective as soon as possible under the Administrative Procedure Act.

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

This rule is adopted pursuant to the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998 & Supplement 2005) (PURA), which provides the commission with the authority to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; §35.004(e), which requires that the commission ensure that ancillary services necessary to facilitate the transmission of electric energy are available at reasonable prices with terms and conditions that are not unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive; §39.001(d), which requires the commission to order competitive rather than regulatory methods to achieve the goals of PURA Chapter 39 to the greatest extent feasible; §39.151(a)(1), which requires that ERCOT ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; §39.151(a)(2), which requires that ERCOT ensure the reliability and adequacy of the regional electrical network; §39.151(a)(4), which requires that ERCOT ensure that electricity production and delivery are accurately accounted for among generators and wholesale buyers in the ERCOT power region; §39.151(c), under which the commission certified ERCOT to perform the functions prescribed by §39.151 for the ERCOT power region; §39.151(d), which requires ERCOT to establish and enforce procedures, consistent with PURA and the commission's rules, relating to the reliability of the regional electrical network and accounting for the production and delivery of electricity among generators and all other market participants, and which makes these ERCOT procedures subject to commission oversight and review; §39.151(i), which permits the commission to delegate authority to ERCOT to enforce operating standards within the ERCOT regional electrical network and to establish and oversee transaction settlement procedures, and which permits the commission to establish the terms and conditions for ERCOT's authority to oversee utility dispatch functions after the introduction of customer choice; and §39.151(j), which requires a retail electric provider, municipally owned utility, electric cooperative, power marketer, transmission and distribution utility, or power generation company to observe all scheduling, operating, planning, reliability, and settlement policies, rules, guidelines, and procedures established by ERCOT.

Cross Reference to Statutes: PURA §§14.002, 35.004(e), 39.001(d), and 39.151.

§25.502. Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas.

(a) **Purpose.** The purpose of this section is to protect the public from harm when wholesale electricity prices in markets operated by the Electric Reliability Council of Texas (ERCOT) in the ERCOT power region are not determined by the normal forces of competition.

(b) **Applicability.** This section applies to any entity, either acting alone or in cooperation with others, that buys or sells at wholesale energy, capacity, or any other wholesale electric service in a market operated by ERCOT in the ERCOT power region; any agent that represents such an entity in such activities; and ERCOT. This section does not limit the commission's authority to ensure reasonable ancillary energy and capacity service prices and to address market power abuse.

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

(1) **Competitive constraint** – A transmission element on which prices to relieve congestion are moderated by the normal forces of competition between multiple, unaffiliated resources.

(2) **Generation entity** – an entity that owns or controls a generation resource.

(3) **Market location** – the location for purposes of financial settlement of a service (*e.g.*, congestion management zone in a zonal market design or a node in a nodal market design).

(4) **Noncompetitive constraint –** A transmission element on which prices to relieve congestion are not moderated by the normal forces of competition between multiple, unaffiliated resources.

(5) **Resource –** a generation resource, or a load capable of complying with ERCOT instructions to reduce or increase the need for electrical energy or to provide an ancillary service (*i.e.*, a "load acting as a resource").

(6) **Resource entity –** an entity that owns or controls a resource.

(d) **Disclosure of offer prices.** ERCOT shall publish on its market information system:

(1) no later than noon of the following calendar day, the identities of all entities submitting offers for which the energy offer price was $300 per megawatt-hour (MWh) or higher, or the capacity offer price was $300 per megawatt per hour (MW/h) or higher, and the corresponding settlement intervals and market locations;

(2) no later than noon of the following calendar day, the identity of any entity whose offer sets a price for energy above $300/MWh (along with the corresponding settlement interval and market location) and the identity of any entity whose offer sets a price for capacity above $300/MW/h (along with the corresponding settlement interval and market location); and

(3) concurrent with the publication of a corrected market clearing price, the identity of any entity who is paid more than the market clearing price for the service and the corresponding settlement interval and market location.

(e) **Control of resources**. Each resource entity shall inform ERCOT as to each resource that it controls, and provide proof that is sufficient for ERCOT to verify control. In addition, the resource entity shall notify ERCOT of any change in control of a resource that it controls no later than 14 calendar days prior to the date that the change in control takes effect, or as soon as possible in a situation where the resource entity cannot meet the 14 calendar day notice requirement. For purposes of this section, "control" means ultimate decision-making authority over how a resource is dispatched and priced, either by virtue of ownership or agreement, and a substantial financial stake in the resource's profitable operation. If a resource is jointly controlled, the resource entities shall inform ERCOT of any right to use an identified portion of the capacity of the resource. Resources under common control shall be considered affiliated.

(f) **Reliability-must-run resources.** Except for the occurrence of a forced outage, a generation entity shall notify ERCOT in writing no later than 90 calendar days prior to the date on which it intends to cease or suspend operation of a generation resource for a period of greater than 180 calendar days. Unless ERCOT has determined that a generation entity's generation resource is not required for ERCOT reliability, the generation entity shall not terminate its registration of the generation resource with ERCOT unless it has transferred the generation resource to a generation entity that has a current resource entity agreement with ERCOT and the transferee registers that generation resource with ERCOT at the time of the transfer.

(1) **Complaint with the commission.** If, after 90 calendar days following ERCOT's receipt of the generation entity's notice, either ERCOT has not informed the

generation entity that the generation resource is not needed for ERCOT reliability or both parties have not signed a reliability-must-run (RMR) agreement for the generation resource, then the generation entity may file a complaint with the commission against ERCOT, pursuant to §22.251 of this title (relating to Review of Electric Reliability Council of Texas (ERCOT) conduct).

(A) The generation entity shall have the burden of proof.

(B) Pursuant to §22.251(d) of this title, absent a showing of good cause to the commission to justify a later deadline, the generation entity's deadline to file the complaint is 35 calendar days after the 90th calendar day following ERCOT's receipt of the notice.

(C) The dispute underlying the complaint is not subject to ERCOT's alternative dispute resolution procedures.

(D) In its complaint, the generation entity may request interim relief pursuant to §22.125 of this title (relating to Interim Relief), an expedited procedural schedule, and identify any special circumstances pertaining to the generation resource at issue.

(E) Pursuant to §22.251(f) of this title, ERCOT shall file a response to the generation entity's complaint and shall include as part of the response all existing, non-privileged documents that support ERCOT's position on the issues identified by the generation entity pursuant to §22.251(d)(1)(C) of this title.

(F) The scope of the complaint may include the need for the RMR service; the reasonable compensation and other terms for the RMR service; the length of the RMR service, including any appropriate RMR exit options; and any other issue pertaining to the RMR service.

(G) Any compensation ordered by the commission shall be effective the 91st calendar day after ERCOT's receipt of the notice. If there is a pre-existing RMR agreement concerning the generation resource, the compensation ordered by the commission shall not become effective until the termination of the pre-existing agreement, unless the commission finds that the pre-existing RMR agreement is not in the public interest.

(H) If the generation entity does not file a complaint with the commission, the generation entity shall be deemed to have accepted ERCOT's most recent offer as of the 115th calendar day after ERCOT's receipt of the notice.

(2) **Out-of-merit-order dispatch.** The generation entity shall maintain the generation resource so that it is available for out-of-merit-order dispatch instruction by ERCOT until:

(A) ERCOT determines that the generation resource is not required for ERCOT reliability;

(B) any RMR agreement takes effect;

(C) the commission determines that the generation resource is not required for ERCOT reliability; or

(D) a commission order requiring the generation entity to provide RMR service takes effect.

(3) **RMR exit strategy.** Unless otherwise ordered by the commission, the implementation of an RMR exit strategy pursuant to ERCOT protocols is not affected by the filing of a complaint pursuant to this subsection.

(g) **Noncompetitive constraints.** ERCOT, through its stakeholder process, shall develop and submit for commission oversight and review protocols to mitigate the price effects of congestion on noncompetitive constraints.

(1) The protocols shall specify a method by which noncompetitive constraints may be distinguished from competitive constraints.

(2) Competitive constraints and noncompetitive constraints shall be designated annually prior to the corresponding auction of annual congestion revenue rights. A constraint may be redesignated on an interim basis.

(3) The protocols shall be designed to ensure that a noncompetitive constraint will not be treated as a competitive constraint.

(4) The protocols shall not take effect until after the commission has exercised its oversight and review authority over these protocols as part of the implementation of the requirements of §25.501 of this title, so that these protocols shall take effect as part of the wholesale market design required by that section. Any subsequent amendment to these protocols shall also be submitted to the commission for oversight and review, and shall not take effect unless ordered by the commission.

(h) **System-wide offer cap.** A supply offer shall not exceed $1,000/MWh or $1,000/MW/h.

This agency hereby certifies that the adoption 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 §25.502, relating to Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas, is hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE ______ DAY OF ________________ 2004.

PUBLIC UTILITY COMMISSION OF TEXAS

____

JULIE PARSLEY, COMMISSIONER

____

PAUL HUDSON, CHAIRMAN

____

BARRY T. SMITHERMAN, COMMISSIONER

Q:\PD\TXR-Rules Management\Rules\Rulemaking Projects\Electric\27917\27917adt.doc