PROJECT NO. 31972

RULEMAKING ON WHOLESALE ELECTRIC MARKET POWER AND RESOURCE ADEQUACY IN THE ERCOT POWER REGION	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ADOPTING AMENDMENT TO §25.502, NEW §25.504 AND NEW §25.505 AS APPROVED AT THE AUGUST 10, 2006, OPEN MEETING

The Public Utility Commission of Texas (commission) adopts an amendment to §25.502, relating to Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas; new §25.504, relating to Wholesale Market Power in the Electric Reliability Council of Texas Power Region; and new §25.505, relating to Resource Adequacy in the Electric Reliability Council of Texas Power Region. The amendment and new rules are adopted with changes to the proposed text as published in the March 10, 2006 issue of the *Texas Register* (31 TexReg 1575). The amendment and new rules establish basic elements of the Energy Reliability Council of Texas (ERCOT) wholesale market design, under authority given the commission under Chapter 39 of the Public Utility Regulatory Act (PURA).

The amendment and new sections are needed to address the interrelated issues of market power, high prices induced by scarcity, investment in generation, and the ability of electricity customers to respond to high prices by reducing demand.

PURA Chapter 39, adopted in 1999, established the framework to implement a competitive electricity market in Texas. In adopting PURA Chapter 39, the Legislature announced the legislative policies and purposes that supported the implementation of customer choice. The Legislature specifically indicated, in PURA §39.001(a), that Chapter 39 was enacted "to protect the public interest during the transition to and in the establishment of a fully competitive electric power industry." Recognizing that the electricity market in ERCOT would not be fully competitive at the time the retail market opened in January 2002, the commission adopted certain provisions to help protect the public interest during the transition to competition.

In Docket No. 23220, *Petition of the Energy Reliability Council of Texas for Approval of the ERCOT Protocols,* Order on Rehearing, (June 1, 2001), the commission found that the establishment of bid caps (or offer caps) was a necessary "circuit breaker" or backstop to prevent the possible exercise of market power by generation entities. Accordingly, the commission ordered ERCOT to establish an offer cap of $1,000 per mega-watt-hour (MWh) for energy that it procures from generation resources. The offer cap was to expire on July 4, 2003 because the commission anticipated that by that date, "any generation entity market power issues will have been better addressed through other means." The Order on Rehearing in Docket No. 23220 also directed ERCOT to file a report with the commission, by October 1, 2001, concerning the implementation of the ERCOT Protocols and recommending various wholesale market design changes.

The commission considered ERCOT's report in Docket No. 24770, *Report of the Energy Reliability Council of Texas (ERCOT) to the PUCT Regarding Implementation of the ERCOT Protocols.* On August 23, 2002, the commission issued Order No. 14 in Docket No. 24770, requiring that the offer price for ancillary services provided to the ERCOT system could not exceed $1,000/MWh for energy and $1,000/mega-watt (MW) per hour for capacity. On April 23, 2002, the commission issued Order No. 20, lifting the July 4, 2003 expiration date for the offer cap established in Docket No. 23220. In its final Order in Docket No. 24770, the commission indicated that it would periodically review the continued need for offer caps.

Also in Docket No. 24770, the commission considered the effect that "hockey-stick" bidding had upon prices for balancing energy during an ice storm on February 24-25, 2003. On May 29, 2003, the commission issued Order No. 22, in which it concluded that it was appropriate to protect the ERCOT market from the impact of hockey-stick bidding and ordered ERCOT to implement a mitigation procedure known as the Modified Competitive Solution Method (MCSM), which limited the impact of hockey-stick bidding when conditions in the ERCOT market suggested that physical or economical withholding might be present. To provide a further deterrent to inappropriate bidding and other forms of gaming, the commission required ERCOT to adopt a "sunshine policy," identifying any bidder who submitted a balancing energy bid in excess of $900 whenever the market clearing price for energy (MCPE) exceeded $900. This complemented the policy already in the ERCOT Protocols requiring next-day identification of entities submitting up balancing energy offers priced higher than $300 per MWh or down balancing energy offers priced less than -$300 per MWh. The commission also indicated that it would defer consideration of other mitigation methods to a subsequent rulemaking project dealing more broadly with market-failure mitigation.

Subsequent to Docket No. 24770, the commission adopted §25.502, relating to Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas, effective January 9, 2005. Section 25.502(h) codified the offer caps established in Docket No. 24770. Section 25.502(d) changed the level at which the "sunshine policy" established in Docket No. 24770 was initiated from $900 per MWh to $300 per MWh, to reflect a Protocol revision voluntarily adopted by ERCOT market participants.

In July 2002, the commission initiated Project No. 26201, *Rulemaking to Address Enforcement of Wholesale Market Rules*, to address the possibility of market power abuse or other forms of market manipulation in the ERCOT market. Project No. 26201 culminated in the adoption of §25.503 of this title, relating to *Oversight of Wholesale Market Participants*, in February 2004. Section 25.503 established the standards that the commission applies in monitoring the activities of entities participating in the ERCOT market, and includes provisions listing the duties of market participants and identifying certain prohibited activities. In comments filed in Project No. 26201, some persons suggested that it would be beneficial if the commission defined the term "market power" as used in §25.503. Because such action was beyond the scope of Project No. 26201, the commission did not adopt a definition of "market power" at that time, but indicated that a definition would be proposed in a future rulemaking project. The commission instituted Project No. 29042, *Rulemaking on Definition of Wholesale Electric Market Power in the ERCOT Power Region*, in December 2003.

In Docket No. 23220, the commission also considered the issue of maintaining an adequate planning reserve margin in ERCOT after the implementation of competition. The commission noted the healthy reserve margin then available in ERCOT (about 25% over forecasted firm demand for summer, 2001) but was concerned whether there were appropriate incentives to maintain a sufficient reserve margin in the future. The commission expressed a desire to rely upon market forces to the greatest extent possible but stated that it "must decide whether the adequacy of reserve margins should be left to market forces, or whether regulations should be created to help ensure a minimum reserve margin and, if so, what regulatory method should be used." In June 2001, the commission initiated Project No. 24255, *PUC Investigation of the Need for Planning Reserve Margin Requirements*, to investigate whether the adequacy of generating-capacity reserve margins should be left to market forces, or whether other means should be created to help ensure a minimum reserve margin.

In October 2005, the commission consolidated these different subjects into a single project so that the impact of revisions in one area could be reflected in the other subjects if necessary. This would facilitate a consistent approach to these important subjects. As a result, in October 2005, the commission merged Projects Nos. 24255 and 29042 into the current project, Project No. 31972. Additionally, the commission decided that issues related to MCSM would also be reviewed in this project.

In this project, the commission is adopting a definition of the term "market power" that is consistent with the definition that is commonly used by the courts. The adoption of this definition will provide additional certainty to market participants as to how the commission will apply the provision of §25.503. The definition will also assist the independent market monitor (IMM) appointed pursuant to §25.365 of this title, relating to *Independent Market Monitor*, in performing its duties. As a result, the commission anticipates that the commission's ability to identify and address market power abuses will be enhanced.

One of the broad objectives of this project is to change the market rules to provide greater assurance that generation companies and developers will invest in the resources needed to supply the electric needs of customers in ERCOT. The means that the commission is adopting to do so is to allow prices to rise in response to a scarcity of resources in the market. The chief alternative to allowing energy prices to rise, in order to provide incentives for investment, is to establish a formal capacity market. The commission considered, earlier in this project, adopting a capacity market for the ERCOT region. Some other regions of the country have tried to provide incentives for investment in generation capacity by adopting capacity markets, such as the installed capacity or ICAP market in the PJM Interconnection. The commission concluded that such markets represent additional regulation, rather than a market approach to providing incentives for investment. These markets have been costly to customers, and there have also been questions about whether they are effective in inducing developers to invest in new generating facilities. The Federal Energy Regulatory Commission said of such markets in its 2004 Staff report on the state of the markets:

> The capacity markets of the Northeast are one major effort to address this issue. Other possible approaches include letting energy prices rise to clear the market and traditional utility planning. Much of the country has no obvious market mechanism to signal the need for new building in advance of shortages. *The success of capacity markets in addressing the issue is not yet proven.*

Allowing energy prices to rise involves modifying the existing offer caps in the market and repealing MCSM. MCSM was intended to serve as a mitigation procedure to protect the market from the impact of hockey-stick bidding in circumstances unlikely to be related to true supply scarcity. It has served that purpose but has also resulted in unpredictable after-the-fact adjustments in market prices, which have undermined the incentive value of high prices in the balancing energy market. The rules adopted in this order, along with features of the new nodal market to be implemented in 2009, will address a broader set of market design issues in a way that should eliminate the concern over hockey-stick bidding in the ERCOT market. The commission's enhanced enforcement capability, as well as the additional disclosures required by the rules, will deter market manipulation more effectively than MCSM. Accordingly, the rule as adopted requires ERCOT to stop using MCSM as of October 1, 2006.

The level of planning reserve margins in ERCOT remains adequate but has declined since the commission addressed the subject in Docket No. 23220. Because of this, the commission has reviewed the offer caps and disclosure requirements that it imposed as part of that decision and the decision in Docket No. 24770. Offer caps, like MCSM can mitigate high prices that would otherwise result from scarcity of resources in the market. The ERCOT market has continued to mature since that time. In addition, prior concerns about the commission having sufficient enforcement tools to prevent market power abuse have been addressed. Therefore, in order to encourage the development of additional resources in Texas, the offer caps previously established in §25.502(h) are replaced with a series of offer caps that will increase gradually as ERCOT moves toward the implementation of a nodal market in 2009. To further the "sunshine policy" that the commission announced in Docket No. 24770 related to hockey-stick bidding, the commission is requiring additional public disclosure of disaggregated pricing data by market participants. Greater transparency of pricing information should deter generation companies from offering unreasonably high prices and should permit broader scrutiny of questionable prices by other market participants and the general public. This broad scrutiny should help in the identification of prices that are the result of market manipulation or market power abuse. These two issues (the level of the price caps and the disclosure rules) are interrelated in their effect on the ERCOT market, and they are a part of a coherent approach to modifying the ERCOT market rules.

The adopted rules also require ERCOT to prepare various reports based upon information provided by market participants, which will allow the commission and other interested persons to monitor the ERCOT reserve margin and need for resources on an on-going basis. This information will enable buyers, sellers and investors to forecast more accurately the need for additional electrical supply in a timely manner and to take appropriate action.

The adopted rules use competitive rather than regulatory methods to achieve the goals of PURA, considering the current stage of development of the ERCOT market. As adopted, the rules are necessary to meet the legislative policy of protecting the public interest during the transition to and in the establishment of a fully competitive electric power industry. The amendment and new sections are competition rules subject to judicial review as specified in PURA §39.001(e). The amendment and new sections are adopted under Project No. 31972.

Comments on the published proposal were received from The Alliance for Retail Markets (ARM); CenterPoint Energy Houston Electric, LLC, (CenterPoint); City of Austin d/b/a/ Austin Energy (Austin Energy); City Public Service of San Antonio, d/b/a/ CPS Energy (CPS Energy); Comverge, Inc.; Constellation Energy Commodities Group, Inc. and Rio Nogales Power Project, L.P. (Constellation Energy); Denton Municipal Electric (DME); the Electric Reliability Council of Texas, Inc. (ERCOT); Energy Data Source LP (EDS); FPL Energy, LLC; Good Company Associates Inc. (Good Company); Lower Colorado River Authority (LCRA); NRG Texas LLC (NRG); Nucor Steel–Texas (Nucor); Occidental Chemical Corp. (Occidental); Office of Public Utility Counsel (OPC); Reliant Energy, Inc. (Reliant); South Texas Electric Cooperative, Inc. (STEC); Texas Electric Cooperatives, Inc. (TEC); Texas Industrial Energy Consumers (TIEC); TXU Cities Steering Committee (TXU Cities); TXU Generation Company LP and TXU Portfolio Management Company LP (collectively, TXU Wholesale); a group comprising Chaparral Steel, EDS, Frontier Associates LLC, and Good Company Associates (collectively, Various parties interested in demand-side issues, or Various Parties); and a group comprising American National Power, Inc., Constellation Energy Commodities Group, Coral Power, LLC, Exelon Generation Co., L.L.C., FPL Energy, LLC, NRG, Sempra Global, and SUEZ Energy Marketing NA, Inc. (collectively, Joint Commenters).

Reply comments were received from ARM, CPS Energy, ERCOT, Joint Commenters, Nucor, OPC, Reliant, STEC, TEC, TXU Wholesale, and TXU Cities.

A public hearing on the amendment and proposed sections was held at commission offices on May 2, 2006, at 9:30 a.m. The comment at the public hearing was limited to a request that the commission provide general clarification about what it expects an energy-only market to provide, and about the role of reserve forecasting. The commission's discussion herein of issues raised in written comments addresses CenterPoint's request.

Preamble questions

In the preamble of the proposed rule as published in the *Texas Register*, the commission invited interested persons to comment on specific questions posed by the commission. The questions, along with the comments and the commission's responses are presented prior to a discussion of other comments on the proposed rules.

1. Definition of market power. The term "exclude competition" is used by the U.S. Supreme Court in the seminal antitrust case *U.S. v. E.I. duPont de Nemours & Co.*, 351 U.S. 377, 76 S.Ct. 994, 100 L.Ed.2d 1264 (1956). Earlier versions of this proposed rule replaced "exclude" with "impair." Please comment on which term would be more suited to a definition of market power applicable to a wholesale electricity market.

OPC, Reliant, STEC and TEC favored use of the word "impair." Reliant said that "exclude" would set a more difficult standard for a finding of market power, as it would preclude the commission from acting until an entity alleged that it was the victim of anticompetitive behavior that either prevented it from entering the market or forced it to exit the market. Reliant further said that "impair" was not inconsistent with the Supreme Court's use of "exclude" in determining the standard for a violation of the Sherman Antitrust Act. While a finding that an entity "impaired competition" does not rise to the level of a violation of antitrust laws, Reliant said, PURA does not require such a standard. PURA §39.157(a) defines market power abuse as practices that "unreasonably restrict, impair or reduce the level of competition," Reliant noted. The commission's responsibility is to allow competition to work, Reliant said, and the commission has the discretion to determine that market power has impaired competition to the point of requiring a solution without waiting for a violation of the Sherman Antitrust Act.

TEC said the ability to impair competition was of primary concern to its members. It asserted that the largest generators in ERCOT do not need to exclude competition in order to benefit from abusive market behavior, adding that their sheer size allows them to benefit simply by withholding generation from the market, thereby abusing wholesale consumers in the marketplace. In its reply comments addressing various commenters, however, TEC expressed its concerned that the proposed market power rules have been compromised to the degree that no firm could be proven to have market power, and that the future of the ERCOT power market will be marked by recurrent price spikes, which will amount to nothing more than a wealth transfer from buyers to sellers participating in the Up Balancing Energy (UBES) market.

STEC said that “impair” was more suitable to use in the definition of market power in a competitive wholesale power market that has not been fully developed. STEC said that while a generator knows it cannot exclude another party from entering into competition in the short term, an entity with market power can place more risk on competitors, force smaller parties to raise their prices to a level that is no longer competitive, and then undercut the prices long enough to weaken the competitor so it can no longer compete. By the time the larger generator accomplished its goal of erecting a barrier to entry, STEC said, the competitive market will have failed. STEC concluded that it is in the exercise of market power in the smaller incremental steps that must be recognized.

On the other hand, Austin Energy, Joint Commenters, NRG, and CPS Energy favored the term "exclude." Austin Energy said "exclude competition" was appropriate if the commission's intent is to rely on the *DuPont* decision and its related case law. Austin Energy asked for clarification as to whether the test for market power is the ability to control prices and exclude competition. CPS Energy also said use of "exclude" would permit the use of the substantial case law. However, CPS Energy further said that the definition should explicitly except periods of scarcity, saying that it would be inappropriate to apply a definition of market power to such periods.

NRG commented that "impair" was vague, and that the commission should augment its proposed definition with that used by the U.S. Department of Justice (DOJ) in its "Horizontal Merger Guidelines." NRG also said the rule should clarify that "competitive levels" of prices include the levels of scarcity prices necessary for an energy-only market to succeed.

Joint Commenters said that the term "exclude" comports with antitrust law, is supported by PURA, and fits the market power abuses in question. "Impair" is too vague and too broad, the group said.

TXU Wholesale recommended that the commission abandon the *DuPont* definition and instead adopt the definition included in the DOJ's "Horizontal Merger Guidelines." TXU Wholesale said that using a definition that simply captures any ability to control prices appears susceptible to use as a way to apply a pivotal-supplier test, which does not properly test for market power. TXU Wholesale said the pivotal-supplier test has been rejected by the commission and should not be resurrected through an overly broad and incorrect definition of market power. In reply comments, Joint Commenters agreed with TXU Wholesale that the DOJ definition is clearer than the definition in the proposed rule and repeated their preference for the DOJ definition. Joint Commenters said they supported the definition in the proposed rule (using “exclude”) as a way of resolving a contentious issue, but added that they would oppose excluding the legal precedents surrounding the DOJ definition from the application of the definition in the proposed rule.

TXU Cities supported a definition that accounts for the use of individual or collective means to raise prices above a competitive level, but stated that the commission should not include the concept of trying to identify the ability to control prices focused upon a single generation entity. The definition proposed by TXU Cities focused on “the existence of market prices for energy and capacity together above a competitive level,” without testing whether such prices were caused by any individual entity.

Commission response

The commission finds that the definition contained in the *DuPont* case is appropriate for use in determining the existence of market power in the ERCOT markets. Under this definition, market power exists if an entity has the ability to control prices *or* the ability to exclude competition.

The commission declines to adopt the definition of market power contained in the DOJ’s “Horizontal Merger Guidelines” as proposed by some commenters. The DOJ definition is too narrow and does not reach all of the aspects of market power that the commission must address under PURA §39.157. In a statement to the Committee on the Judiciary of the

United States House of Representatives on July 28, 1999, the DOJ acknowledged that its authority "to enforce the antitrust laws with respect to the electric power industry does not sufficiently address the ability of electric utilities to exercise market power that can thwart free competition within the industry." The Guidelines clearly indicate that they are only concerned with "horizontal acquisitions and mergers subject to … section 1 of the Sherman Act." The courts have held that section 1 of the Sherman Act only applies to concerted action, not unilateral conduct. *Monsanto Co. v. Spray-Rite Service Corp.*, 465 U.S. 752, 104 S.Ct. 1464, 79 L.Ed.2d 775 (1984). Courts may impose antitrust liability on the basis of unilateral conduct only under section 2 of the Sherman Act, which prohibits monopolization and attempts to monopolize. *Aspen Skiing Co. v. Aspen Highlands Skiing Corp.* , 472 U.S. 585, 105 S.Ct. 2847, 86 L.Ed.2d 467 (1985). The types of market power abuses that the commission is charged with addressing under PURA §39.157 are primarily based upon unilateral conduct (*e.g.*, withholding of production), although collusion by multiple parties is also included. These actions are more analogous to violations of section 2 of the Sherman Act. In contrast, PURA §39.158 deals with mergers and acquisitions and specifies a standard of review not based on the definition of "market power" but based on the level of installed generation capacity specified in PURA §39.154. This analysis is analogous to the DOJ's use of market share analysis to determine whether concerted action violates section 1 of the Sherman Act. Accordingly, the commission finds that the definition of market power used by the DOJ for reviewing mergers is not sufficient for all of the types of conduct that the commission must review under PURA §39.157. The commission finds that the definition from the *DuPont* case, which is used in cases involving

section 1 of the Sherman Act, is more appropriate for the determination of the existence of "market power" in the ERCOT markets.

In adopting this definition, the commission stresses two important points. First, simply having market power is not a violation of PURA or commission rules. The existence of market power is a necessary precondition to a finding of market power abuse, but by itself it does not imply any wrongdoing. Second, the definition of market power addresses *capability* and therefore need only address what an entity *can* do. The definition does not require that market power be exercised before it can be found to exist.

Although the commission is not using the term "impair competition" as some parties suggested, that does not mean that the commission will not review whether a market participant's actions can impair competition in ERCOT. PURA §39.157 clearly directs the commission to address market power abuses, which include practices that "tend to unreasonably restrict, *impair,* or reduce the level of competition." (Emphasis added.) The commission notes that the definition of "exclude" in Webster's *Ninth New Collegiate Dictionary* includes "to expel or bar esp. from a place previously occupied," as well as "to prevent or bar the entrance of." Therefore, the use of the term "exclude competition" covers both actions that prevent new participants from entering the market and actions that cause existing participants to leave the market. In response to the comments requesting that the commission use the term "impair competition," the commission is adding the statutory definition of "market power abuse" to the adopted rule. This will provide assurances to those commenters that the commission is cognizant of its statutory

role under PURA §39.157 and will clarify the commission's intent in adopting the *DuPont* definition of "market power."

The adoption of the *DuPont* definition does not mean that the commission has rejected the pivotal-supplier test as a market power screen. While the rule does not require the use of a pivotal-supplier test, neither does it preclude its use in determining the existence of market power. The commission believes that it is premature to rule on the appropriateness of using a pivotal-supplier test for two reasons. First, the soon-to-be-appointed Independent Market Monitor (IMM) should be given enough flexibility to make an initial determination, in accordance with the IMM's own professional judgment, concerning what type of market power screen – including a pivotal-supplier test – is appropriate for the ERCOT market. Second, in the absence of the IMM's recommendations concerning market power screens, the commission prefers at this time to judge the appropriateness of any particular market power test and its detailed methodology in the context of an enforcement proceeding where such a test is being used as evidence of market power. To be clear, the commission did not reject the pivotal-supplier test; it rejected the idea that this rule should endorse any particular test. A party may choose to offer a pivotal-supplier test as evidence of market power, and if sufficiently supported, the test may be found valid by the commission.

The commission declines to adopt the definition of market power proposed by TXU Cities. The analysis of market power, as courts have developed it in the context of antitrust law, focuses on the size and other advantages of particular firms in a relevant market. The

analysis may include an examination of whether a firm may be able to set prices at levels that are above the competitive market price. Nonetheless, the focus is on particular firms, and the commission concludes that a similar analysis is required here. It appears that TXU Cities' definition would result in all market participants being found to have market power if even one generator received "excessive returns." The commission also concludes that PURA primarily focuses on specific firms and their size and conduct. To the extent that market power exists and is exercised by groups of market participants, it may be addressed through the prohibition on collusion contained within PURA §39.157 and §25.503(g)(6) of this title. PURA §39.001 evidences a clear Legislative policy to support competition in the production and sale of electricity. The overbroad definition of market power proposed by TXU Cities conflicts with this policy.

2. Disclosure of disaggregated data. With respect to proposed §25.505(f), the commission seeks comment on potential commercial impacts of disclosing disaggregated, resource/qualified scheduling entity (QSE) specific, offer and quantity information two days after real-time and disclosing other information after 30 days. The commission has received general comments on the potential impacts of the disclosure of disaggregated offer information, but requests that commenters please articulate clear examples of potential commercial impacts to your company that will result from disclosure of each specific type of information and how the rule could be revised to address those impacts.

OPC supported the market-transparency provisions of §25.505(f), saying that disclosure would bring tremendous benefits to the market and that market participants will likely be able to make better business decisions with the added information than without. It said the commission should analyze the consequences of asymmetric information in the market, i.e. the ability of some market participants to glean the information on their own while the information is unavailable to others.

Noting that ancillary service capacity offers and energy offer curve information are the most critical pieces of information to be made available under the rule, Reliant recommended making aggregate data available within 24 hours. Entity-specific data for entities that do not qualify for the market power exemption established by §25.504 should be disclosed within 48 hours, with other entities' data disclosed later (but sooner than 30 days.) Reliant noted that any potential commercial impacts on entities due to this increased market transparency must be balanced with the necessity for load-serving entities to have confidence that market prices are driven by competition, not by abuses of market power. Reliant added that dynamic schedules are not as crucial as offer curve data and could be disclosed later. It also noted, however, that in a nodal market entities could provide generation output schedules for resources not providing an energy offer curve, which could be a method of exercising market power.

Reliant also said that because "firm scheduled load" and "scheduled load" are not defined terms in the protocols for a nodal market, "firm" should be deleted in reference to a nodal market. It said further that "bids with 'up to' limits" would be appropriate. Reliant also noted that ERCOT will be unable to post actual load data as required by subsection (f)(2)(D) until settlement is complete 180 days after the operating day.

Austin Energy recommended disclosing disaggregated data after 30 days (rather than 48 hours) and aggregated data after 60 days (rather than 30 days). Generally, Austin Energy said that untimely disclosure could give an asymmetric advantage to sellers, allowing sellers to artificially raise prices to consumers. It cited disclosure of resource output and self-arranged quantities as examples. Austin Energy also said sellers may be subjected to intense public scrutiny of legitimate business decisions, which would be warranted only when it can be established by the commission that the benefit of public disclosure of an entity's otherwise privileged business data clearly outweighs the negative competitive consequences to the entity. Austin Energy also said real-time information (other than market prices) would not create additional incentives for investment.

With respect to disclosure of disaggregated data, STEC commented that the disclosure requirements would allow larger market participants to gain critical resource and scheduling information about smaller market participants, thereby allowing the larger entities to impair the competitive ability of the smaller entities. As an example, STEC said a larger entity could use the information to create significant congestion for smaller entities under a nodal market design, thereby making electric cooperatives and small municipal utilities more hesitant to opt for competition. Only the larger companies would have the staff and resources to effectively analyze and use such information, STEC said.

CPS Energy supported the release of disaggregated information at 6 months, as it is currently practiced by ERCOT. At a minimum, CPS Energy argued, the confidentiality must be maintained for three months after the operating day.

CPS Energy emphasized that PURA does not authorize the disclosure of disaggregated information from municipally-owned utilities as required by the proposed rule. CPS Energy cited PURA §40.004 and stated that it expressly limits the commission's jurisdiction over MOUs to certain purposes including requiring reports of municipally-owned utilities only to the extent necessary to enable the commission to determine the aggregate load and energy requirements of the state. Since the proposed disclosure is not necessary for the commission to determine the state's aggregate load and energy requirements, it is impermissible, CPS Energy concluded. In its reply comments, STEC supported CPS Energy's comments.

Joint Commenters said that while market transparency benefits competition, disclosure of confidential business information harms competition. They commented that market transparency does not mean disclosure of information protected by law; that the Legislature, Congress and the courts have held that protecting transaction-specific information serves the public interest; that parties advocating quick disclosure of information are advancing that position because the information is commercially valuable; and that disclosure could neutralize a company's efforts to earn revenues from market advantages accomplished through prudent management, efficiency, investment and innovation, and heighten its risk associated with temporary or longer-term market vulnerabilities. Joint Commenters disputed the statement in the preamble to the proposed rule that disclosure "will enhance competition and will also enhance the commission's enforcement efforts by providing increased scrutiny of market participants by other market participants and the public." They said that under PURA, assessing market competitiveness is a function not of market participants but of the IMM and the commission, and that PURA requires the protection of competitively sensitive information.

While most of Joint Commenters' analysis addressed disclosure in general terms, one point they made addressed the specific question posed by the commission in the preamble. Continuous disclosure of bid curves rather than simply market-clearing prices can reveal far more new information about small entities than large ones, Joint Commenters said, thereby harming small suppliers significantly more than large suppliers. They also said large competitors are more likely to have resources to use that information in competing against small competitors.

Joint Commenters also contended that a rulemaking is not an appropriate procedure for imposing disclosure requirements such as those that would be required under subsection (f)(2). They cited a Texas Supreme Court ruling in *Industrial Foundation of the South v. Texas Industrial Accident Board*, 540 S.W.2d. 668 (Tex. 1976), *cert. denied*, 430 U.S. 931 (1977), that said an agency may not adopt a rule classifying specific types of information subject to the Texas Public Information Act (TPIA) as confidential. Joint Commenters asserted that the proposed rule implicitly determines that the specified disaggregated data are confidential for the 48-hour period of non-disclosure, and explicitly determines that the data are not confidential after that period. The court held that an agency could not bring information within the TPIA exception for confidential information by promulgation of a rule, Joint Commenters said, therefore an agency also cannot, without express authority, adopt a rule classifying specific types of information as not confidential. They added that public interests involving disclosure can be protected through a variety of procedures, including TPIA requests, attorney general opinions, and ERCOT Protocol procedures.

Any disclosure requirement should not discriminate among market participants, Joint Commenters said. They opposed Reliant's suggestion of having greater disclosure for large market participants, even though the Joint Commenters membership comprises mostly small suppliers. They also said the commission should not adopt the provision before the Texas Supreme Court decided whether to hear an appeal of the Third Court of Appeals' decision in *Public Utility Commission v. City of Garland, et.al.,* (*City of Garland*) 165 S.W.3d 814 (Tex. App. - Austin 2005, pet. denied).

TXU Wholesale argued against the release of the data within 48 hours, and stated that the disclosure would allow the sophisticated market participants to use such information in a perfectly legal manner to the disadvantage of the overall ERCOT market. TXU Wholesale stated that by using the information, sophisticated market participants would be able to determine the market positions of particular market participants (whether long or short in generation supply among other things). This knowledge is invaluable in negotiating bilateral contracts. Additionally the disclosure of the information would allow sophisticated market participants to track price gaps in the ERCOT-administered auctions and fill those gaps with offers that raise the average clearing prices over time. Constellation agreed that their market positions could be discerned and they would be harmed by this disclosure. They noted that anonymity of position allows market participants to offer and bid closer to where they are willing to transact, rather than where they will make the most profit.

Constellation stated that the proposal to release entity-specific information would publicly disclose and thus destroy the commercial value of competitively sensitive information and trade secrets of Constellation and other market participants and the release of entity-specific information even after 90 days could be problematic in some instances.

FPL noted its belief that there are problems that result from the disclosure of the information after 48 hours. The first is that the information would likely be used by other market participants to manipulate ERCOT markets to secure commercial advantage at the expense of those who disclose information in good faith. The second is that this would result in the ERCOT markets becoming increasingly hostile to new market participants, increasingly less attractive to new generation investment by current market participants and increasingly less robust and competitive.

Commission response

The commission disagrees with the argument of CPS Energy that the commission's authority over municipally-owned utilities is limited to the authority granted by PURA §40.004. The new rules do not create any new requirement for market participants to provide reports to the commission, so reliance on PURA §40.004 is misplaced. The rules only address disclosure of information that market participants provide to ERCOT to enable ERCOT to perform its functions as an independent organization under PURA, including the scheduling of transactions and the acquisition of ancillary services. PURA §35.004(e) requires the commission to ensure that ancillary services are available at

reasonable prices and are not unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive. PURA §35.001 includes a municipally-owned utility within the definition of electric utility for purposes of PURA Chapter 35. Additionally, PURA §39.151(d) allows the commission to adopt and enforce rules related to the operation of ERCOT and other independent organizations established by the commission. PURA §39.151(j) requires that ERCOT market participants, expressly including municipally-owned utilities, must comply with the rules and Protocols adopted by ERCOT and authorizes the commission to bring an enforcement action against a market participant that fails to comply with the Protocols. The commission finds that these statutory provisions give the commission sufficient authority over ERCOT and market participants, including municipally-owned utilities, to require the disclosure of the information addressed in the rule.

Confidentiality of information provided to ERCOT is currently addressed in Section 1.3 of the ERCOT Protocols. Pursuant to Protocol Section 1.3.1.1, much of the information addressed in the proposed rule is treated as confidential. However, Section 1.3.3 states that the protected status that applies to the confidential information expires 180 days after the applicable operating day. The time limit on the protection provided by the Protocols indicates that such information is not confidential for all time. If the information was a trade secret *per se*, the disclosure of which would reveal business strategies or business formulas, it would presumably remain confidential indefinitely. Because the Protocols allow disclosure after 180 days, the information is currently available to competitors after that time. During the past four-year period, ERCOT routinely has released the

information after 180 days. Potential competitors therefore already have access to this information, on a delayed basis, and can perform the "reverse engineering" that the commenters apparently fear. Therefore, any potential impact from the disclosure of the information has already occurred, and the rule does not create the threat to disclosure as alleged by the commenters.

Requiring disclosure of information does not conflict with the public policy expressed in PURA §39.001(b)(4) that the commission should "ensure the confidentiality of competitively sensitive information." The rule does ensure the confidentiality of competitively sensitive information, but only for the period of time in which it is competitively sensitive. By operating under the existing ERCOT Protocols, the market participants are implicitly agreeing that their claims of confidentiality expire over time. The question faced by the commission is whether 180 days is an appropriate period of time; in other words, do the claims of confidentiality become stale after a shorter period of time, and, if so, is the public interest served by mandating shorter disclosure timelines? The commission has received conflicting suggestions on this issue, ranging from disclosure after only 48 hours to disclosure pursuant to the current 180-day time period in the Protocols. Based upon the comments, the commission has determined that it is appropriate to limit the period of time during which some information is considered competitively sensitive.

Contrary to the arguments from some commenters, the commission may make this decision in a rulemaking proceeding and need not conduct a contested case for such purpose. The Administrative Procedure Act (APA), Texas Government Code §2001.003(6) defines a

“rule” as “a state agency statement of general applicability that implements, interprets, or prescribes law or policy.” The courts have recognized that, “unless mandated by statute, the choice to proceed by general rule or by ad hoc adjudication is one that lies primarily in the informed discretion of the agency.” *State Board of Insurance v. Deffebach,* 631 S.W.2d 794, 799 (Tex. Civ. App. – Austin 1982, writ ref’d n.r.e.) Because the current disclosure requirements are addressed in the ERCOT Protocols, which are similar to rules, and because these disclosure requirements will affect all market participants in the same manner, the commission determines that it is particularly appropriate to use the rulemaking process to address the issue in this instance. Cases cited by Joint Commenters for the proposition that an agency cannot *expand* the list of exemptions to public disclosure are not relevant to the question of whether an agency can establish a rule related to a schedule for the disclosure of information.

The commission disagrees with comments that the now-final Third Court decision in the *City of Garland* case prevents the commission from addressing disclosure standards for market participants or requires the commission to adopt a different standard for public power utilities. The opinion in *City of Garland* only addressed the cities’ claims of confidentiality of certain contract information under §552.133 of the Texas Government Code. The Court, in a footnote, stated, “We express no opinion regarding the Commission’s power to determine for itself other claims of confidentiality, including assertions based upon other TPIA exceptions.” Therefore the decision does not preclude the commission from determining whether market information submitted to ERCOT should be disclosed to the public.

The decision also does not compel a different standard for municipally-owned utilities. PURA §35.004(e) requires that ERCOT's acquisition of ancillary services shall not be unreasonably discriminatory or anticompetitive. Having two different standards is inconsistent with this requirement. Further under §552.133 of the Texas Government Code, a public power utility's designation of a matter as confidential can be overturned if (1) the governing board of the public power utility failed to act in good faith or (2) the information is not reasonably related to a competitive matter. "Competitive matter" is defined as a matter that is "related to the public power utility's competitive activity, including commercial information, and would, if disclosed, give advantage to competitors or prospective competitors." The commission questions how requiring a municipally-owned utility to disclose information subject to the same requirements that apply to all other market participants could be considered to "give advantage to competitors or potential competitors." Because the rule creates a level playing field relative to the disclosure of disaggregated information, it does not provide a competitive advantage to any market participant. The commission believes that a decision by the governing body of a public power utility to insist on a different and more advantageous position concerning disclosure would be subject to attack as not being made in good faith. For these reasons, the commission declines to adopt a different standard for public power utilities.

As noted previously, since the start of retail open access, the commission has viewed the level of the offer cap and the appropriate amount of information disclosure to be interrelated. Because the commission has decided to increase the offer caps in order to

encourage greater investment in generation and load resources in Texas, it believes that such increases must be accompanied by increased disclosure of the information that affects the operation of the ERCOT market. The increased disclosure will help to ensure that price changes are the result of a properly functioning competitive market and not the result of market power abuse or other market manipulation. The commission agrees with comments suggesting that it should require a more rapid disclosure of certain market information.

However, the commission is also sympathetic to the concerns expressed by other commenters that the time periods contained in the proposed rule as published may have been too short. The disclosure of large amounts of information after 48 hours, as originally proposed, could allow some market participants to use the information to the detriment of other participants. In order to avoid this result, the commission agrees that, for most of the information subject to the rule, disclosure after 48 hours is not necessary or appropriate.

In balancing the concerns of the commenters on both sides of this issue, the commission has determined that it would be appropriate to change the disclosure requirement on a gradual basis. This will enable both the commission and the market participants to become accustomed to the new disclosure procedure and make any necessary changes to their operations. The implementation schedule for disclosure is also being tied to the schedule for increases to the offer cap, thereby further emphasizing the commission's decision that these two issues are interrelated. Under the revised disclosure schedule contained in the rule, effective March 1, 2007, most of the required disaggregated information will be

disclosed 90 days after the day for which the information was accumulated. This is one-half of the current disclosure timeframe of 180 days, but much longer than the 48 hour to 30 day time periods contained in the proposed rule. On the same date, the offer cap contained in the rule will increase from $1,000 per MWh to $1,500 per MWh. Effective March 1, 2008, the disclosure of disaggregated information will take place 60 days after the date the information was accumulated. This corresponds to the date that the offer cap is increased to $2,250 per MWh. Finally, two months after the market begins operation under a nodal market design (approximately March 1, 2009), the disclosure period is reduced to 30 days while the offer cap is raised to $3,000 per MWh.

One major exception to this disclosure schedule concerns offer curves for balancing energy and ancillary services. These two areas raise the greatest concerns about the possibility of market power abuse and other market manipulation. In order to provide greater transparency to the public and other affected market participants in these areas, the commission believes that it is appropriate to require the disclosure of offer curves for these services on a more expedited basis. Balancing some market participants' concerns about disclosure against the greater need for public scrutiny, the commission concludes that, as a general rule, the offer curves should be disclosed 30 days after the day for which the information was accumulated, beginning October 1, 2006, rather than the previously proposed 48 hours.

However, the commission believes that there is an important public objective to be served by requiring the disclosure of pricing information soon after market prices are determined.

Offers that set market prices should be subject to public scrutiny and discussion, without the constraints of confidentiality. In order to facilitate such scrutiny and discussion, the commission believes that some basic information should be subject to disclosure after 48 hours. The commission is revising the rule to require disclosure of only the amount of the highest-priced offer selected or dispatched by ERCOT and the name of the entity submitting that offer. This information would be provided for each interval and, if interzonal congestion is involved, the disclosure would provide the required information for each separate zone. Thus under the rule as revised, ERCOT would post the following information 48 hours after the day for which it was accumulated: the date, the interval, the name of the entity(s) involved, and the price (and, if applicable, the zone involved). The rule requires the posting of the highest price selected but not all of the offer curve associated with that price, and it is not requiring 48 hour disclosure of the names of entities other than the one whose bid is the highest selected. Two months after the start of operation of the nodal market, the requirement for posting of information for separate zones would be deleted and ERCOT would only be required to post the information for the highest-priced offer selected or dispatched by ERCOT for each interval on an ERCOT-wide basis. By limiting the 48-hour disclosure requirement in this fashion, the commission can provide public information concerning the entity that had the greatest impact on the market clearing price without affecting other market participants. In adopting this disclosure requirement, the commission emphasizes that the disclosure of information after 48 hours pursuant to this rule does not imply any wrongdoing by the market participant whose information is disclosed.

The commission agrees with comments that the scope of the information to be disclosed under the proposed rule was too broad. The proposed rule required the disclosure of certain load information on an accelerated basis. The commission believes that rapid disclosure of this information is not needed to address the market manipulation concerns noted previously. Accordingly, the commission has revised the rule language by omitting the requirement to disclose this load information on an accelerated basis. This action also addresses some of the concerns expressed by commenters that disclosure could impact the competitive position of market participants. The commission has also clarified the rule language in some areas to more correctly state the disclosure requirements. Finally, because the commission is adopting a schedule for phased implementation of the disclosure requirements, there may be some confusion concerning when the requirements of §25.502(d) would expire. To avoid any confusion, the commission revises §25.502(d)(4) to indicate that the subsection expires on October 1, 2006.

3. Credit requirements. The commission seeks comment on whether the credit requirements for QSEs in the current ERCOT Protocols will be sufficient if the offer caps are raised to the levels proposed in § 25.505(f)(i). If the current requirements will not be sufficient after the adoption of the proposed rule, should modifications or additional credit requirements be specified in a commission-sponsored rulemaking, or left to the ERCOT stakeholder process? If such modification or additional requirements should be specified in this rulemaking, then please provide recommended language and corresponding rationale, for possible adoption as part of §25.505.

OPC stated that the credit requirements are based on the exposure of an entity to default and that a relaxation of the offer caps would increase the price exposure of the market participants and therefore their credit exposure. OPC commented that to maintain the same level of credit protection in a regime where energy prices are likely to be higher requires higher credit requirements. OPC, Reliant, and STEC all noted that higher credit requirements could create a barrier to entry and cautioned the commission to be mindful of this concern while trying to strike an appropriate balance. OPC opined that the ERCOT stakeholder process and the credit working group tend to emphasize protecting the marketplace over worrying about barriers to entry, because it is impossible to have new entrants into the market represented by stakeholders. OPC commented that left alone ERCOT will modify its credit requirements to recognize the new risk.

In its comments Joint Commenters noted that in an energy-only market, generation investment will be recovered in select hours instead of over 8760 hours of the year. Load serving entities (LSEs) that "ride" the balancing energy market instead of contracting for energy with a wholesaler will run the risk of running up huge debt within a short period of time. Joint Commenters commented that credit requirements would have to be increased. Joint Commenters stated that this question reflects concern that some LSEs would not hedge against this potential risk and imperil the rest of the market. Joint Commenters noted that in the Australian market the credit requirements reflect this increased socialized risk. Joint Commenters stated that if the commissioners receive appropriate credit recommendations in comments the issue should be addressed in §25.505, but Joint Commenters did not make any specific recommendations.

ERCOT commented that it believes it has sufficient latitude and flexibility under the current ERCOT Protocols to make timely adjustments to QSE collateral requirements for changes in a QSE's credit exposure. ERCOT noted that the changes the rule contemplates would increase the potential for volatility in the market and ERCOT would continue to develop and use the tools it needs to perform the monitoring necessary to reduce to subsequent risk to the market. In reply comments ERCOT stated that it agreed with commenters who stated that the ERCOT stakeholder process was the appropriate forum to make changes to the credit requirements should the commission deem them appropriate.

Reliant commented that the ERCOT credit requirements are sufficient if offer caps are raised provided that the ease of LSE market entry is matched by defaulting LSE removal from participation in that market because allowing the transfer of the defaulting LSE's customers to provider of last resort as soon as possible reduces the exposure of the remaining market participants to the defaulting LSE's credit insufficiency. Reliant advocated using the stakeholder process to determine the appropriate credit requirement should the commission decide that ERCOT's current requirements are insufficient for the implementation of the higher offer caps.

NRG stated that the ERCOT stakeholder process is adequate to address the credit requirements but agreed with other commenters that some broad guidance from the commission is appropriate considering that an energy-only market would produce potentially volatile and higher energy prices.

STEC commented that while it understands what the commission is endeavoring to accomplish through the high low offer caps in this rule, the answer to this question demonstrates the fallacy of the rule's use of these offer caps as an answer to solve the problem of resource and reserve adequacy. STEC contended that it is unlikely that the current credit requirement will be sufficient to protect the market participants from bearing additional costs due to defaults caused by rising power costs. STEC expressed concern for smaller entities forced into the spot market due to facility outages, noting that larger entities seldom incur unnecessary costs to protect their customers from unjust enrichment from certain players. STEC was concerned that higher credit risk is harmful for entities that provide power using the cooperative model because they operate at cost. STEC argued that government should refrain from placing credit risks on market participants and also commented that the commission should not address those credit requirements in the rule, but rather should give the stakeholders the opportunity to address the issue first.

CPS Energy opined that even if the rule achieves its goal of providing for resource adequacy it will fail in its objectives if that resource adequacy is paid for by an uplift of bills left unpaid by the market. CPS Energy stated that while the rule recognizes that adequate credit standards are important it is unclear what "credit standards … consistent with this section" means. CPS Energy believed it would be difficult to provide specific credit requirements in the rule and that such development should be left to the ERCOT stakeholder process. CPS Energy further recommended that §25.505(g) be deleted from the rule and that the commission recognize the need to establish appropriate and equitable credit standards for QSEs in the rule's preamble based on the increased potential financial exposure that could result for the ERCOT market from the implementation of §25.505.

In reply comments, Reliant agreed with CPS Energy' recommendation to delete §25.505(g) from the proposed rule.

Austin Energy supported stricter collateral standards in ERCOT if the offer caps are raised. Austin Energy believed that the ERCOT Credit Working Group is the proper forum for discussions and recommendations for credit requirements. Austin Energy recommended that the commission direct the working group to consider the credit implications of the higher offer caps and that ERCOT provide a report and recommendations to the commission within 60 days of the final adoption of §25.505.

In reply comments ARM and ERCOT disagreed with Austin Energy's recommendation to require an accelerated timeline for ERCOT's Credit Working Group to resolve the credit issues. ARM commented that it would be more reasonable to give stakeholders the time required to achieve consensus. ARM argued that the outcome of the negotiations could be considered by the commission in the context of the protocols required to be developed to implement the energy-only market. Reliant stated in reply that the commission has oversight of the protocols and should monitor the market's response to the changes that result from the rule's implementation.

TXU Wholesale offered specific recommendations addressing its concerns regarding increased credit exposure. TXU Wholesale stated that increased risk requires strengthening of the credit requirements and the commission must specify what the credit requirements should be. First, TXU Wholesale suggested that ERCOT change its total estimated liability calculation from 40 days of market exposure to a minimum of 60 days of market exposure, and preferably 90 days of market exposure. Second, the balancing energy factor should be set higher to allow ERCOT to mitigate a higher percentage of the potential exposure. Third, ERCOT should use commercially reasonable measures to be more vigilant in monitoring the credit-worthiness of QSEs. Fourth, ERCOT should use the daily peaking price, not the daily weighted average price to create a more realistic approximation of an at-risk load shape. Fifth, a QSE's scheduling privileges should be suspended when its Estimated Aggregate Liability reaches 85% of its posted security, rather than when it reaches 100%.

In reply comments ARM disagreed with TXU Wholesale that the current credit requirements are not sufficient for the higher caps proposed for the energy-only market. ARM agreed with ERCOT that the current credit requirements have the flexibility to set a QSE's collateral requirements and that stakeholders can work to develop additional proposals on the issue. ERCOT and Reliant also disagreed with TXU Wholesale's comments asking the commission to direct ERCOT to make specific changes and again recommended the stakeholder process as the forum for considering the changes sought by TXU Wholesale.

DME expressed concerns about how the credit requirements would be determined. It noted the logic in increasing the requirements due to the higher caps but was also concerned that more stringent credit requirements would impose disproportionate impacts on smaller market participants. It requested that the commission give due consideration to the potential impacts of the credit requirements on the smaller entities. DME stated that while it was not opposed to letting the stakeholders deliberate and present a recommendation to the commission regarding credit in the energy-only market it would like to see the commission have direct involvement in the process, even if only to have final approval or disapproval of any stakeholder developed credit requirements.

LCRA commented that it did not believe that the credit requirements under the current resource adequacy structure are adequate and although it supports the ERCOT process for changing the protocols, the credit issue is a sensitive and difficult issue that has major policy implications for the market. Therefore, LCRA supported a commission rulemaking regarding the ERCOT credit standards with the involvement of market participants, but did not support including language in §25.505 regarding credit.

Reliant disagreed with LCRA that the commission should institute a rulemaking to affect any changes relating to credit standards.

STEC replied that the credit issues should not be resolved in this rulemaking but that it believed a rulemaking addressing the issue is desirable because commission, stakeholder, and ERCOT involvement are all necessary.

ARM supported the language in the rule as proposed and opposed any effort to modify ERCOT's credit requirements through a commission rulemaking proceeding. Any impact on credit requirements posed by the resource adequacy rule should be dealt with through the ERCOT stakeholder process. However, ARM did not believe any changes would be necessary. The credit process is already designed to increase credit requirements when credit exposure increases and the nodal protocols introduce additional credit requirements on QSEs with respect to participation in the day-ahead market and congestion revenue right auction. The additional information made available through the proposed rule in the form of the projected assessment of system adequacy (PASA) allows a market participant to hedge its risk and therefore better manage exposure in the market. The proposed rule also requires protocols to be filed with PUCT; therefore market participants could propose amendments to credit requirements as part of that process.

ARM suggested that the rulemaking is not the appropriate forum to debate the merits of various potential approaches to reforming the ERCOT credit standards and it would be more appropriate to address the issue in the stakeholder process. This has the advantage of developing a set of standards that are supported by a majority of market participants.

TEC stated that raising the high cap (HCAP) would have two effects on QSEs, namely, increased revenues for those entities that have excess capacity and increased risk for those QSEs that have to shore up their energy supplies in the balancing energy services market. TEC said that larger firms with large generation portfolios would benefit. As credit requirements are predicated on market risk, the requirements of smaller QSEs are likely to increase and the requirements to larger firms, decline. This is unacceptable and increases the gap between the larger and smaller firms.

Commission response

The commission agrees with CPS Energy and other commenters who commented that the energy-only resource adequacy mechanism may require a re-evaluation of the existing credit standards and that the language in the proposed rule was not adequate. The comments demonstrate that the issue of appropriate credit standards is complex and related to a number of changes that are occurring in the market. The necessary review of the issue cannot be accomplished in the relatively short time remaining for the review of the proposed rule. Therefore the commission deletes §25.505(g) from the rule. Further, the commission encourages the market participants to work together to address this issue and, at this time, will leave any changes in ERCOT's credit policies to the ERCOT stakeholder process. The commission will monitor the development of credit requirements along with the implementation of the energy-only resource adequacy mechanism and may raise this issue again in the future if sufficient progress is not made.

4. Considerations in setting the levels of the system-wide offer cap. The commission seeks comment on the appropriate levels of the system-wide offer caps from the implementation date of §25.505 through 2009. When commenting on this issue, please address what factors impact your answers, including those listed below:

(a) The appropriate length (number of hours) and intensity (level of prices) of scarcity pricing for the ERCOT market. For instance, greater number of hours allowed for scarcity pricing would result is a lower cap applied in each hour to reach the $150,000 threshold in proposed §25.505(i)(5)(iv). Conversely, a shorter time would allow a higher individual cap. The commission seeks input on how to balance these two variables.

(b) The appropriate level of the HCAP that would strongly encourage forward contracting for resources by load-serving entities.

(c) The projected reserve margin through 2010, as presented in ERCOT's most recent report on capacity, demand, and reserves.

(d) The level of HCAP that would encourage more demand-side participation (industrial loads, large commercial loads, small commercial loads, residential loads, energy efficiency programs) in current or planned ERCOT-operated markets (both real-time and centralized day-ahead). Please include a discussion of what factors, besides the level of the offer cap, may influence loads to increase their demand-side response in these markets.

CPS Energy said that both theory and experience support an offer cap that is no lower than $7,500 per MWh, noting that for the 88 hours during the year when the highest demand occurs, the ERCOT and Australian load duration curves are quite similar. Joint Commenters, quoting an earlier filing with the commission, noted that the load duration curve of the entire Australian National Electricity Market Management Company (NEMMCO) market is different from ERCOT, and the comparison with South Australia and Victoria is not appropriate.

CPS Energy contended that actual scarcity pricing only occurred 0.20% of the time, or about 17.5 hours per year, implying an offer cap of $8,500 in ERCOT. In Australia during 2004, prices were above $A3,000 (Australian dollars) during these times and accounted for more than 16% of the generator revenues ($A 1.2 billion out of $A7.7 billion). CPS Energy inferred that the application of the equivalent of a $3,000 per MWh offer cap that removed over $A 1 billion in revenue from the $A 7.7 billion Australian electricity market would have significant negative implications for investment and resource adequacy in that energy-only market.

CPS Energy noted that most economists define scarcity conditions in electric markets as periods of shortage when supplies are insufficient to meet energy and ancillary service demands in real time. CPS Energy said it was difficult to reconcile this definition of scarcity with the expectation in the proposed rule that scarcity pricing will occur in the ERCOT market for 50 hours per year. CPS Energy questioned whether prices could reach scarcity levels at times that, by the standard economic definition, are not representative of true scarcity conditions.

According to CPS Energy, if scarcity conditions are defined to mean periods of shortage when supplies are insufficient to meet energy and ancillary-service demands in real time, then reaching such price levels for such a duration is extremely unlikely. CPS Energy suggested defining scarcity pricing conditions as all the time periods when demand is greater than 93% of the projected peak demand, when planning reserve margins for the year are calculated to be less than 12.5%, and when supplies are insufficient to meet energy and ancillary service demands.

Commission response

The commission acknowledges that the resource adequacy mechanism in the rule is based upon the Australian wholesale electricity market, adjusted to meet the specific circumstances of the ERCOT market. However, the commission notes differences between the ERCOT and the Australian NEMMCO markets that suggest that the offer cap in ERCOT does not need to be at NEMMCO's level to meet the resource adequacy needs of the ERCOT market. The higher offer cap in NEMMCO was developed to account for the duration curve in the South Australia and Victoria areas, which reflect sharper peaks than in ERCOT. Because of this and other differences, the commission finds that ERCOT does not require an offer cap to be set at NEMMCO levels to meet ERCOT's resource adequacy needs.

CPS Energy and Joint Commenters, in their comments, asked the commission to provide a definition or some guidance on what constitutes scarcity pricing. The commission believes that such a definition is unnecessary. The rule permits prices to rise to the level of the HCAP for a limited number of hours. The rise to these levels could be caused by legitimate scarcity conditions, but they could also be the result of market power abuse. It will require significant analysis to recognize instances in which prices rise as a consequence of market power. Providing a definition of scarcity would not facilitate the operation of the pricing mechanisms set out in the rule or the identification of market power abuses. Defining "scarcity pricing" would, however, risk legitimizing a high price that was in fact the result of market power abuse. Therefore, the commission declines to adopt a definition of "scarcity pricing."

Joint Commenters included an analysis of the market power rule and energy-only resource adequacy mechanism by Dr. Ross Baldick that supported the contention by Joint Commenters that the proposed rule would not provide generators with sufficient opportunities to recover their fixed costs under the proposed energy-only resource adequacy rule. Dr. Baldick's analysis was based on numerous premises and assertions, including: offer prices by generators are never more than 25% above marginal costs, and the highest energy offer price is not more than 25% above the highest marginal cost; use of reserves to produce energy is not reflected in the energy price; energy prices will reach their system-wide offer cap only during periods of involuntary load curtailments, which ideally should be no more than three hours per year; high-demand years occur on average only one out of three years, meaning that peakers make zero inframarginal profits two out of three years; about 18 hours a year of prices at the system-wide offer cap means that many hours of rotating blackouts would occur; load resources will refuse to participate in the market if their offers are accepted too frequently; and price caps to load resources should be higher than to generators for demand response to occur.

Commission response

Much of the analysis and conclusions presented by Dr. Baldick were based on a series of assumptions, hypotheses and statements that were unrealistic, not supported by experience and appeared to reflect a misconception of the rule and of certain details in the Texas Nodal Protocols. There is no support, for example, for the assumption that generators' offers do not exceed 25% above their marginal costs. ERCOT has experienced market clearing prices in excess of $600 per MWH, which is clearly more than 25% above the

marginal costs of most of the units in ERCOT. Furthermore, to the extent that MCSM and the current $1,000 offer cap may have prevented higher prices, those constraints are being loosened or eliminated by the new rules. As discussed later in this order, the peaker net margin (PNM) is being increased to twice the annualized fixed cost of a new peaker. This should allow greater opportunity for low capacity-factor units to recover their fixed costs. In addition, the Texas Nodal Protocols have a provision for a "proxy generator" that will introduce scarcity pricing into the real-time energy market when responsive reserves are being deployed. Projections about the frequency and duration of involuntary load curtailments also fail to reflect the impact that the higher offer caps will have on load participation in the market. Further, there is no support for the assumption that prices approaching the system-wide offer cap can only occur during rolling blackouts. Finally, as discussed later, the commission has decided to eliminate the emergency load response (ELR) concept at this time, so assumptions and objections based upon the ELR mechanism are not applicable to the rules as adopted. For these reasons, the commission has not adopted Dr. Baldick's recommendations.

CPS Energy, in its reply comments, noted that those who advocated the maintenance or reduction of the current $1,000 per MWh offer cap either did not understand the economics and incentives that must be present for an energy-only resource adequacy mechanism to be successful, or are actually advocating for the ultimate abandonment of the energy-only idea in favor of a capacity market. Though CPS Energy still prefers a capacity market approach to resource adequacy, its comments reflect a desire to make the commission's choice of an energy-only resource adequacy mechanism succeed in meeting the physical requirements of the system and the economic principles that are embodied in an energy-only market design.

Commission response

The commission agrees with CPS Energy that the maintenance or reduction in the current $1,000 per MWh offer cap is not compatible with a sustainable energy-only resource adequacy mechanism.

Reliant stated that the scarcity pricing mechanism (SPM) should not be adopted because it moves away from competitive market solutions and instead overlays a prescriptively administered regulatory construct. Reliant stated its concern that there will be insufficient demand response in ERCOT for the energy-only market design to work. Reliant stated that there are demand-side technological flaws such as the lack of metering and real-time billing for sizeable portions of the load that ultimately point to a capacity market alternative for ERCOT. Reliant renewed its opposition to an energy-only resource adequacy mechanism.

Reliant expressed the opinion that regulators would be unable to distinguish between scarcity pricing and market power abuse and that bilateral contracting was a risk management tool, not a resource adequacy issue. Reliant noted that from 1999 through 2005, ERCOT experienced a wave of generation construction without contracting requirements. Joint Commenters, in their reply comments, disagreed with Reliant's position that bilateral contracts were a risk management issue and not a resource adequacy issue. Joint Commenters stated that bilateral contracts were both a risk hedging instrument and one way to finance new generation capacity.

Commission response

The commission agrees with Reliant that the ERCOT market needs more price-responsive load in place and it will be taking steps to remove impediments to market-based demand response in Project No. 32853, *Evaluation of Demand-Response Programs in the Competitive Electric Market.* The commission believes that by working with the IMM, it will be able to distinguish between market power abuse and legitimate scarcity pricing. In any event, the difficulty in differentiating market power abuse and scarcity does not warrant adopting an alternative resource-adequacy mechanism.

NRG did not support the proposed system-wide offer caps and stated its concern with the overall direction of the rule. NRG stated that during the vast majority of high demand hours, there will be significant competitive pressure on generators to bid, which disciplines prices regardless of mitigation measures. NRG stated that the proposed caps are far too low to work, given the infrequency and irregularity with which real supply scarcity can occur in a market with adequate resources. Because there will be few hours of scarcity pricing – from 2 to 20 hours per year – energy prices will need to consistently reach averages that may be as low as $4,000 per MWh to as high as $30,000 per MWh. NRG cited statements in the *2004 State of the Market Report for the ERCOT Wholesale Electricity Market* as evidence that unmitigated bids alone would lead to insufficient scarcity pricing.

Commission response

The commission disagrees that the system-wide offer cap needs to be as high as NRG has suggested. The commission notes that the *2004 State of the Market* report was written about a market with a $1,000 offer cap. While the commission agrees that a $1,000 offer cap is not sustainable in an energy-only resource adequacy mechanism, the comments in the *State of the Market Report* are not indicative of the sustainability of an energy-only resource adequacy mechanism with an offer cap of $3,000 per MWh.

NRG stated that an energy-only mechanism must be augmented by other mechanisms that will dependably set very high prices whenever reserve levels are compromised or threatened. NRG called for the development of explicit reserve shortage energy-pricing mechanisms that can produce scarcity pricing without relying on offers from the market.

NRG stated that experience with chronically under-supplied markets in other regions suggests that as reserve margins erode, reliability is degraded and policymakers become increasingly concerned about the potential for sustained periods of high prices that could erode popular support for competition and that are easily confused with the exercise of market power, as was seen in the energy crisis in California. Joint Commenters stated that because the offer cap is applied to all generation units, not just those that could be used to abuse market power, the proposed rule’s offer cap is not aimed at market power abuse.

Consistent with recommendations by Drs. Patton and Hogan, NRG proposed that energy prices be directly set at appropriately high levels when reserve levels are at risk of being degraded.

Joint Commenters offered a different but comparable approach by suggesting that the commission add a new subsection in the rule to raise the offer cap to $10,000 per MWh when there is insufficient capacity offered in the market to meet ERCOT's ancillary service needs. Joint Commenters noted that this proposal addresses what it perceives as the failure of the rules to specify the conditions when scarcity pricing arises. NRG supported the Joint Commenters suggestions to modify the SPM. In its reply comments, CPS Energy recommended that the rule require an administrative demand curve but recommended that the specific mechanics should be reserved for resolution through the stakeholder process.

In its reply comments, ARM urged the commission to reject this approach. ARM expressed its strong opposition to administratively reducing scarcity pricing in balancing energy prices when reserves are depleted. ARM emphasized that scarcity prices have occurred under the existing rules within the bounds of the current caps. ARM stated that the proposed less-than-5% market power safe harbor mechanism will ensure that small entities will be able to attempt to extract scarcity rents through balancing energy prices when such entities are pivotal during scarcity conditions. These small entities will attempt naturally to induce scarcity prices into the market price for balancing energy. This situation is different than is found in the U.S. power market outside of ERCOT where there is no such market power safe harbor and market monitoring actions may be aggressive enough to preclude any entity from attempting to extract scarcity rents. Administratively inducing scarcity prices would amount to a subsidy like those that would be provided through capacity markets.

Joint Commenters, in its reply comments, expressed skepticism with ARM's assertion that the 5% market power safe harbor would permit sufficient scarcity pricing for the market because market participants would drive down the price towards short-run marginal costs unless there is true scarcity in the market, where scarcity is defined as involuntary load curtailment.

Commission response

The commission concludes that these comments are inconsistent with the actual experience in ERCOT markets. Prices in the balancing energy and capacity markets have reflected changes in supply and demand, and the relaxation of the existing pricing and bidding restrictions should result in prices that reflect the scarcity of resources. The commission also notes that the market has experienced high prices without a mechanism to administratively set prices during periods of scarcity. Furthermore, the nodal market protocols approved by this commission have such a mechanism, which incorporates administratively set high-priced energy offers into the real-time energy offer stack when ERCOT needs to deploy responsive reserve service in response to insufficient energy offers in the real-time market. As a result, the commission does not see the necessity of adopting additional measures to ensure scarcity pricing and declines to amend the rule as suggested by Joint Commenters and NRG.

NRG suggested that suppliers with larger market shares should have explicit safe-harbor bidding rules that protect them from the risk of mitigation while supporting bids significantly above incremental costs.

Commission response

New §25.504 allows generators to apply for a voluntary mitigation plan at the commission, which provides a generator with the chance to have a safe harbor. Once approved, the supplier would have an absolute defense against a finding of market power abuse with respect to the behaviors addressed in the plan, provided the supplier adheres to the approved mitigation plan. The commission believes that, at this time, the option to develop a mitigation plan for individual generator entities is preferable to developing a "one size fits all" plan that would be applicable to all generation entities. The commission may later choose to codify its decisions concerning voluntary mitigation plans once it has had more experience in determining the terms and conditions that are best suited to such plans. The commission therefore declines to adopt NRG's suggestion.

NRG suggested that smaller players and loads acting as resources (LaaRs) should have no mitigation or bidding limits at all. Joint Commenters also suggested that load resources should not be subject to any of the proposed offer caps or, alternatively, should be subject to much higher caps than proposed in the rule. In its reply comments, ARM opposed the NRG proposal. ARM stated that is it appropriate for the commission to limit the transfer of wealth to prevent the sustained receipt of monopoly rents. The commission's HCAP, annual PNM limit, and LCAP concepts together provide such protection and should be applied to all generation in the balancing energy market. Moreover, the scarcity pricing mechanism (SPM) is not designed as a market power mitigation mechanism. The SPM does not obviate the need for a market power rule. ARM urged the commission to reject NRG's proposal.

Commission response

The commission agrees with the points raised in ARM's reply to NRG. Until the demand response in the ERCOT market increases significantly, there will be a need for mechanisms to protect the public interest and prevent market power abuses and market manipulation. The mechanisms contained in the rule provide that protection and the commission sees no need to exclude load resources from their reach. The commission therefore rejects the suggestions from NRG and Joint Commenters that loads and smaller market players should not be subject to the offer caps in the rule.

TXU Cities opposed the adoption of the proposed offer caps. TXU Cities stated that the general concept of scarcity pricing doesn't make sense and that it does not believe that a single-price energy-only electricity market can promote economic efficiency, as Substantive Rule 25.501(a) requires, because the market prices may not always reflect short run marginal costs (SRMC). DME expressed concern that the proposed level of the offer cap was too high and would drive loads to engage in short-term contracting to avoid locking into high-priced long-term contracts that resources would offer them.

TXU Cities, in its reply comments, stated that the resource adequacy debate in ERCOT replicates similar debates that have occurred in other parts of the country and that, given that the fundamental resource adequacy issues confronting ERCOT are not unique, the commission should not try to reinvent the wheel. The commission needs to ensure the ERCOT market has a sufficient level of financial incentives to guarantee that investors will build an adequate amount of new generation capacity over time. TXU Cities, in its reply comments, stated that it believes that a competitive market provides efficient incentives for supply and demand. TXU Cities asserted that a single-price auction type is not a competitive market and that it does not provide efficient price signals and financial incentives. The arbitrary nature of the underlying basis for these bids, which sets the prices for all generation in the market, suggests that such prices could not possibly be economically efficient. Even if the market clearing prices were linked directly to costs, the fact that all generation entities dispatched at the same time are paid the same market clearing price sends false and inefficient price signals for the purpose of planning the transmission system.

Commission response

The commission rejects the proposition of TXU Cities that the single clearing price auction market in electricity produces neither competitive outcomes nor efficient price signals for market entry and exit. Such markets have been used for more than two centuries and many economists have agreed that such a market design is the benchmark for measuring the competitiveness of a market. The characteristics of electricity markets – lack of cost-effective storage, limited price-responsive demand, and severe transportation limitations – pose unique problems for electricity regulators. The overwhelming majority of electricity economists, however, expressed publicly that these problems do not undermine the market incentives embedded in a single-price competitive auction. The commission declines to adopt the changes proposed by TXU Cities.

TXU Cities expressed concern that there is no bright line between hours of the year when power is "scarce" and, therefore, deserves high prices well above marginal operating costs, and hours when power is not scarce and should be priced at marginal operating costs. TXU Cities stated that one of the major problems with an energy-only electricity market is that neither a generation owner nor a market monitor can possibly know if each owner will cover its annual fixed costs for each of its generating units from the price it is paid in the market. Because the annualized fixed costs cannot be collected on a routine and dependable basis as the year goes by due to the inherently volatile spot market, the market can't be monitored for market power.

Commission response

The commission agrees that there are risks for both buyers and sellers in the ERCOT market. These risks are no greater than risks associated with other commodity and financial markets in the world today, market risks that market participants, both buyers and sellers, have been successfully managing for decades. The energy-only resource adequacy mechanism may require that market participants use different hedging tools than they would in a market with a different resource-adequacy mechanism, but it does not mean that market participants will be unable to manage risks in ERCOT. The commission disagrees with TXU Cities' contention that the market cannot be monitored for market power. The IMM will have the authority and resources to investigate any potential instances of market power abuse. Nothing in the rule prevents the commission from taking enforcement action against any market participant found to have engaged in market power abuse or other violations of PURA or the ERCOT Protocols. Further, the voluntary mitigation plans allowed by the rule will enable the commission and market participants to resolve potential market power abuses without the need for an enforcement action.

TXU Cities, in its reply comments, suggested that the commission set a required reserve margin for each load serving entity in Texas for a period of at least 3-4 years in order to meet its entire projected load plus an adequate reserve margin in each of those future years, with severe financial penalties if the reserve margin is not met. If the load serving entity did not contract for the capacity, then the LSE would be required to invest in and construct this new capacity. If the construction of new capacity was the least cost avenue for ratepayers, this approach would be naturally selected.

Commission response

TXU Cities' proposal is inconsistent with the competitive market established by PURA. PURA §31.002(17) specifically prohibits a retail electric provider (REP) from owning or operating generation. In contrast, the proposed rules are consistent with the legislative policy in PURA §39.001 that electric services and prices should be determined by competitive forces.

In its reply comments, TXU Cities quoted a paper by economists Peter Cramton and Steven Stoft (included by Reliant in its initial comments) in which the authors assert that "there cannot yet be a market for reliability" due, in part, to the lack of sufficient infrastructure investment in the transmissions system.

Commission response

TXU Cities' reliance upon the Cramton and Stoft paper is misplaced. That analysis was based on an assumption that necessary infrastructure for price-responsive demand would

not be available for ten years. This assumption is unfounded. Certain large loads participate in ancillary services markets, and ERCOT is currently implementing protocol changes to gain greater participation from LaaRs. Additionally, the commission has initiated Project No. 32853 to address various demand response issues -- such as expanding the percentage of large loads covered by interval data recording meters (IDRs) -- in order to further encourage the development of opportunities for demand participation in the ERCOT markets. A separate project is considering issues related to advanced metering, which should give customers access to more discrete information on their consumption and could result in time-of-use pricing for customers for whom it is not now an option.

TXU Cities stated that it is impossible to eliminate the boom-bust investment cycles and lower regulatory risk to acceptable levels if an energy-only balancing market is solely relied upon to provide the proper price signals to ensure resource adequacy. Prices are either extremely high or extremely low.

Commission response

The commission agrees that even under proposed resource-adequacy mechanism, ERCOT may experience a boom-and-bust resource investment cycle. Demand-side response can act as a shock absorber in any boom-and-bust investment cycles, where certain loads will curtail more often in years of shortages than years of plenty. ERCOT has policies that allow new resources to quickly and easily enter the market. Price-responsive demand will curb some instance of high prices. Additionally, loads have the ability to arrange multiple-year contracts, which can protect loads from high spot market prices in years with lean

reserve margins. While these aspects of the ERCOT market do not eliminate a possible boom-and-bust cycle, they mitigate its impact. In any event, the possibility of such a cycle does not justify the conclusion that the balancing market under an energy-only resource adequacy mechanism will not provide proper price signals to ensure resource adequacy. Moreover, it is not clear that other mechanisms for ensuring resource adequacy are effective, much less capable of avoiding boom-and-bust cycles.

TXU Cities proposed that a potentially competitive market structure would be similar to the type of wholesale auction held in New Jersey where bids are solicited for a percentage of the load of a given distribution utility. In this case, bidders would need to put together a least cost package of baseload, cycling, and peaking capacity and energy when creating their bids. In general, the most economical use of generation resources occurs when the sum of all variable and fixed costs for generation meeting load is minimized over the long run.

TXU Cities, in its reply comments, stated that the use of bid price caps does not adequately protect retail customers from the presence of market power in an energy-only market. Adjusting the numerical values of such price caps up or down administratively as circumstances in the market change is just another form of rate regulation, albeit a weak and uncertain form that does not ensure that retail consumers are protected from the existence of market power.

CPS Energy, in its reply comments, stated that TXU Cities' suggestion that the ERCOT wholesale market be totally reformed to implement a pay-as-bid approach was flawed, going so far as to suggest that the bid part of the equation be set at cost plus a reasonable profit. The inefficiencies and problems associated with a pay-as-bid approach are well-documented in academic literature. CPS Energy noted that the second part of the proposal – to implement a form of cost-based pricing – sounds much like regulation. This approach is in violation of PURA and even worse than regulation, because it would lead to resource inadequacy. CPS Energy recommended that the commission reject all of TXU Cities' proposed changes.

Reliant, in its reply comments, disagreed with TXU Cities' recommendation to scrap the existing market structure in favor of "NJ-style" auctions whereby bids are solicited for a percentage of load of a given distribution utility. Reliant noted that this market structure is not permitted by law, and would abandon the most successful retail market in the country in favor of a less successful pseudo-competition model.

Commission response

The commission agrees with CPS Energy and Reliant that the TXU Cities' approach is flawed, would introduce inefficiencies and problems into the ERCOT market, would undermine a successful retail market and is in violation of the legislative policy supporting the development of a fully competitive electric power industry. The commission therefore declines to make the changes suggested by TXU Cities.

TEC stated that raising offer caps discriminates against smaller QSEs and will allow firms with market power to increase the rents they can extract from the market. TEC stated the appropriate length of and intensity of "scarcity pricing" allowed in ERCOT should be zero. It claimed that concerns over the ability of currently installed super-peaking capacity to recover its capital costs under the present cap reflect a plea to justify continued use of uneconomical assets.

TEC stated that the current level of the offer caps should not significantly impact future peaking projects and capacity expansions, because such assets are not constructed contingent on prices in the balancing energy market. TEC believed that continued load growth in ERCOT, reliance on an ever-aging generation fleet, and continued uncertainty about coal transport and high gas prices may drive reserve margins down to 10% at the end of the decade.

TEC stated that the appropriate level of HCAP that would strongly encourage bilateral contracts is infinity. TEC expressed concern that while real-time energy prices in Australia are low, no analysis has been made to determine how much prices were raised in the Australian bilateral energy market. TEC suggested that bilateral contracts in Australia pay a premium to cover concerns over high spot market prices, providing an unnecessary windfall to sellers.

Commission response

The commission concludes that scarcity pricing is an appropriate tool for maintaining adequate reserves in a competitive market. Contrary to TEC's assertions, existing peaking capacity is uneconomical only if more economical alternatives are available to meet demand during the superpeak hours of the year. This rule is intended to encourage the development of such alternatives by providing incentives for the development of *new* peaking capacity. While it is true that a new peaker's profitability is not necessarily a function of what it gets paid for balancing energy, market expectations for the MCPE do

influence the expected bilateral contract prices upon which investment decisions are made. The protection of a stable bilateral contract will become more valuable to load-serving entities as price risk increases in the balancing energy market. This does not constitute an unnecessary windfall to sellers. In the commission's view, it is simply a risk premium, similar to what arises in every competitive market where uncertainty is a factor. Adoption of TEC's proposal would inhibit the development of new peaking capacity and actually prolong ERCOT's reliance upon older, less efficient peaking units.

TEC stated that participation in demand-side management programs is unlikely to be impacted by the value of HCAP. Given that most consumers have an inelastic demand for firm electricity service, customers' billing statements will not correlate peak usage to average prices paid for electricity and most current metering devices will not support demand-side management (DSM). Reliant, in its reply comments, agreed with TEC's position.

Commission response

The commission agrees that the price elasticity of demand is limited by the lack of interval metering for many loads and plans to address this shortcoming in Project Nos. 31418 and 32853. In Project No. 32853, the commission will consider such proposals as expanding the number of large loads that use IDR meters to settle those loads using real-time consumption rather than load profiles. Project No. 31418 will consider requiring features on advanced meters for residential and other small loads to provide retailers with more accurate electricity usage than monthly billings and average load profiles. To reduce the impediments to market-based demand-side response in ERCOT-procured markets, the

commission also will consider accelerating the implementation of certain protocol revision requests (PRRs). There is some level of interval metering that is used for wholesale settlement and retail pricing today, and these changes will improve load response to the MCPE over time. The commission sees no need to change the rule in response to the comments of TEC and Reliant.

TEC proposed to use a mechanism for recovery of costs for super-peak assets in the marketplace that has been approved for the California market. This solution would replace the "hard" offer caps currently in place at $1,000 per MWh with a "soft" cap at a lower level designed to limit consumer exposure to price spikes. Unlike a "hard" cap, sellers are allowed to bid resources into the market at prices above the "soft" cap; however, if sold, those resources will have no impact on the prices of other power sold in the market.

TEC stated that the "soft cap" methodology has three advantages. First, consumers that enter the balancing energy market would be partially insulated from price spikes resulting from scarcity conditions and abusive market behavior. Second, firms seeking to recover costs of "super-peaking" units can charge whatever price the market will bear for those specific resources without impacting the prices paid for resources purchased at or under the cap. Third, the long-term market signals required to encourage the construction of additional capacity will remain intact, as the room under the soft cap will allow resource providers to garner prices significantly above those needed to support efficient units.

Good Company stated that between 2002 and 2004, ERCOT experienced only 30 hours in which prices in the balancing energy market exceeded $300. Prices should be allowed to rise sufficiently to finance new generation and encourage responses by consumers to the risk of exposure to higher prices.

ARM replied that TEC's proposal was flawed. Entities that control generation in excess of the 5% installed capacity market power safe harbor might be unable to bid in excess of short-run margin costs due to market monitoring concerns. TEC's soft cap would unduly deny these entities the ability to earn scarcity rents, since the market price for balancing energy would not be allowed to reflect scarcity. Because TEC's soft cap would prevent the market price for balancing energy from reflecting scarcity, the incentive provided by higher price caps for long-term forward contracting by load serving entities would be eliminated under TEC's proposal. CPS Energy, in its reply comments, stated that the TEC soft cap was a pay-as-bid approach for all accepted offers greater than the soft cap, with the payments to be uplifted. CPS Energy strongly opposed the soft cap mechanism, because it is entirely inconsistent with the fundamental principles underlying competitive wholesale markets, especially in an energy-only market.

TEC, in its reply comments, stated that ARM used faulty logic to support the proposed HCAP. According to TEC, what ARM ignored was that no profit-maximizing firm would ever invest money in a generation resource solely contingent upon that resource being profitable in the balancing energy market. TEC also stated that absent a defined load for the resource coupled with a bilateral agreement designed to cover capacity charges, it is highly unlikely that raising the offer caps will do anything other than place consumers and small generators at grave market risk. TEC stated that the proposed rule, with the phased-in HCAP, would distort the goal of ensuring future resource adequacy to further the economic interests of large generators with existing capacity.

Commission response

The commission agrees with the reply comments of ARM and CPS Energy regarding TEC's soft cap proposal. The commission believes TEC's approach is inconsistent with the fundamental principles of competitive wholesale markets and is inconsistent with an energy-only resource adequacy mechanism. The commission agrees with Good Company that prices should be allowed to rise sufficiently to encourage new generation. Therefore, the commission declines to amend the rule to incorporate TEC's suggested revisions.

CPS Energy and TXU Wholesale expressed concern that the proposed offer cap of $3,000 per MWh was too low for the energy-only mechanism to be successful. CPS Energy noted that the Australian market has been successful because the offer cap is currently at the equivalent of $7,500 per MWh. CPS Energy stated its belief that the value of lost load (VOLL) in ERCOT is higher than $3,000 per MWh, and that, in the long run, the offer cap has to be equal to VOLL to avoid involuntary curtailments during summer peak. TXU Wholesale suggested starting with a $6,000 per MWh offer cap in March 2007 and gradually raising the cap to $10,000 per MWh in 2009. In its view, VOLL for Texas customers is in the $6,000 to $10,000 per MWh range. Therefore, HCAP should be set at that level.

CPS Energy stated that if capacity additions are required and market prices are insufficient to support the investment, additional generation is not likely to be built. CPS Energy believed that the commission should demonstrate confidence to the industry and the investment community regarding its commitment to an energy-only market by implementing the full level of the offer cap on September 1, 2006. ARM replied that the final HCAP does not need to be phased in any faster than the commission proposed because resource adequacy appears to be sufficient until 2010.

TXU Wholesale opined that the proposed scarcity pricing mechanism (SPM) just expands regulation by imposing lower price caps on the entire market, thereby endangering the commission's goal of ensuring resource adequacy. TXU Wholesale and Joint Commenters also asserted that the HCAP is too low to ensure sufficient bilateral contracting to meet the commission's resource adequacy goals. Joint Commenters contended that the proposed rule will not produce sufficient demand-side response and that the demand bids should not be capped or should have very high caps.

ARM suggested that the final HCAP to be phased in by March 1, 2009 be $6,000 per MWh, to ensure that the annual PNM limit can be reached without involuntary load curtailment. ARM opined that the projected reserve margins through 2010 show that resource adequacy likely will be more than sufficient through 2009. ARM believed that the transition to the HCAP should be completed by March 2009, based on the past boom of generation building and the recently announced coal and wind projects that are driven by projected infra-marginal profit opportunities. ARM asserted that these fundamentals are only transitory in nature. In the event that the commission decides to retain the $150,000 per MW PNM limit, then the commission should adopt an offer cap of $5,000 per MWh instead of $6,000 per MWh.

Joint Commenters, in comparing the load duration curves of the Australian and ERCOT markets, drew the conclusion that the offer cap in ERCOT should be higher than the offer cap of $A10,000 in the Australian market. Joint Commenters also said that the caps would rarely be reached, given certain provisions in Substantive Rules §25.504 and §25.505.

Joint Commenters also contended that the offer cap is too low to meet the one-day-in-ten-years loss of load probability (LOLP) standard, citing several studies. Joint Commenters and NRG proposed to raise the cap or eliminate the offer cap for load resources as a way to ensure resource adequacy through scarcity pricing.

Joint Commenters were concerned that the commission will impose substantial bid caps and other obstacles to adequate revenue recovery, resulting in resource shortages. Much of the announced generation is never built, and the existing generation fleet in ERCOT is old. Joint Commenters, in their reply comments, noted that Dr. Baldick stated that much of this older capacity is likely to be decommissioned.

ARM stated that setting the HCAP too low would not allow some resources with low capacity factors to earn sufficient revenues in the market and might require involuntary curtailments of load. ARM assumed that scarcity pricing would generally occur when load levels reached at least 95% of peak load, when entities granted the safe harbor provision in the market power rule would be pivotal in the balancing energy market. With a $1,000/MWh offer cap and only 30 hours of significant scarcity pricing, for instance, the PNM would be only $27,600/MW per year, not sufficient to provide a competitive investment opportunity for generation developers. The commission's proposed $3,000 offer cap would permit a maximum recovery of $87,000/MW per year.

ARM proposed an HCAP of $5,000 to 6,000 to allow resources the opportunity to recover fixed costs under the assumption of 30 hours of scarcity pricing per year. These higher levels would encourage forward contracting and maximize demand-side participation. Maximum demand-side participation occurs when scarcity premiums are concentrated into the smallest number of hours possible.

ARM, in its reply comments, agreed that the proposed HCAP value of $3,000 per MWh is not sufficient due to the infrequent occurrence of scarcity conditions. ARM did not agree with CPS Energy, however, that the HCAP needs to be set at VOLL. Instead, ARM stated that the annual PNM limit can be realized without involuntary load curtailments. Moreover, the annual PNM limit should be set to a value that presents a revenue opportunity that is sufficient to make investments in a new peaking generation facility competitive compared to other investment opportunities.

In its reply comments, OPC opposed the changes in the HCAP that ARM proposed. OPC believed that an HCAP greater than $1,000 per MWh would strongly encourage forward contracting. OPC stated its preference for longer hours at a lower cap. OPC stated its belief that the principal barrier to demand-side participation in both the current zonal and future nodal market design would be difficulties in synchronizing the market with demand-side response rather than the level of the HCAP.

LCRA stated that the proposed HCAP levels are more than sufficient to serve their intended purpose.

Reliant suggested that the commission delete subsection (i), that this mechanism is not a true energy-only mechanism, and that debating the level of offer cap has little or no meaning. Reliant and STEC proposed that the commission retain the $1,000 per MWh offer cap until there is a study that clearly demonstrates that what has been used for the past five years doesn’t work and what the potential for demand-side response will be in ERCOT. STEC urged the commission to leave the offer cap at $1,000 per MWh until it investigates further if the discrepancy between the high and low reserve margin caused by the mothballing of units is reasonable and justified.

ARM replied that without involuntary curtailments, an offer cap of $1,000 per MWh will not provide a sufficient investment opportunity for new generation development for resource adequacy and to attempt this empirically would require the commission to risk market failure and its associated resource inadequacy.

STEC replied that although TXU Wholesale and Joint Commenters have presented plausible arguments with respect to the level of the system-wide offer cap, STEC believed that Reliant has provided compelling reasons for leaving the current offer cap in place until the issue has been properly studied. STEC believed that the offer cap might be sufficient, and that this argument was given more credence in light of the recent announcements of plans to build new generation plants in ERCOT.

Commission response

The commission agrees with comments that maintaining the current offer cap of $1,000 per MWh would have deleterious effects on the ERCOT market. Without raising the offer cap to higher levels, the owners of generation and load resources will not have sufficient incentives to be available when additional supply is needed. Under an energy-only resource adequacy mechanism, ERCOT cannot rely on a daily "must-offer" requirement or capacity payments to ensure that sufficient resources are available in those situations. A higher offer cap will provide strong incentives for investment in quick-start generation and load response to meet demand in unusual market situations. Additionally, the commission believes that a $1,000 per MWh offer cap would require market participants to lean too heavily on load resources and existing generation to meet peak demand. While a $1,000 offer cap should provide sufficient incentives for market participants to build and to contract for new baseload, intermediate, and intermittent renewable generation, there is some evidence in other electricity markets that a $1,000 per MWh offer cap might not provide incentives for sufficient new peaking generation to enter the ERCOT market. Therefore, the commission declines to amend the rule to set the HCAP at $1,000 per MWh or lower as recommended by STEC, Reliant, and others.

The commission agrees that the average level of VOLL is higher than the $1,000 per MWh offer cap that is currently in effect in ERCOT. That fact also supports the commission's decision to increase the offer cap in this rule, but it does not mean that the offer caps should be raised to the same level as in the Australian market. As discussed previously, there are important differences between the ERCOT market and the Australian market and the commission does not need to raise the offer cap to Australian levels in order to assure resource adequacy in ERCOT. Additionally, the value of lost load is different for different customers, and the higher caps being adopted in this rule should provide additional incentives for customers to adjust their consumption in response to high prices. The commission and market participants are also taking steps to remove impediments to market-based demand response. The implementation of these new steps, including advanced metering and expanded time of use pricing, will increase the level of price-responsive load in ERCOT. This will enable the offer caps to remain lower than Australian levels. Given the prospect for increased levels of load participation in the ERCOT market and assuming that a sizeable amount of the new baseload generation recently announced by TXU Wholesale, CPS Energy, and others will come online in ERCOT by 2010, the commission does not find compelling evidence that ERCOT requires an offer cap at Australian levels. Therefore, the commission declines to raise the HCAP to $7,500 per MWh or higher as suggested by various commenters.

The commission has decided to phase in the increase in the HCAP over a three-year period rather than immediately for the following reasons. First, the commission notes that a number of features of this rule, such as the statement of opportunities (SOO) and the

PASA, are based on the assumption that developers need three years to install new gas-fired generation in ERCOT. Therefore, the offer cap that will exist two to three years in the future, not the prevailing offer cap, is the relevant offer cap for investors making decisions on whether to build new generation in ERCOT.

Second, the commission believes that the market will need some time to increase load participation in ERCOT significantly. The commission agrees with the comments that the energy-only resource adequacy mechanism will work more effectively when a wider and deeper range of load response is available in the market. However, increasing the participation by price-responsive load may not result solely from higher price caps, and commission action to remove the impediments that currently exist in ERCOT may be important. The commission plans to increase the amount of price-responsive load in ERCOT. The IMM can play an important role in helping the commission assess the progress of the energy-only resource adequacy mechanism. The commission will have sufficient opportunity to consider a different HCAP if the level of new generation investment and price-responsive load is not sufficient at the $3,000 per MWh offer cap.

Third, the commission has reviewed ERCOT's projections of the planning reserve margin for the next few years and agrees with ARM that the projected reserve margins in ERCOT allow the commission to gradually raise the level of the HCAP over a period of three years. The commission also believes that the termination of MCSM and the gradual rise in the offer cap in the amended language in this rule should provide sufficient incentive to keep

enough existing peaking resources online to meet projected summer peak demand during the three-year phase-in period.

For the reasons stated above, the commission disagrees with the assertion of CPS Energy and others that the full offer cap should be instituted as soon as possible. The commission has determined that raising the offer cap in one step by the end of this year would cause an unnecessary transfer of wealth from loads to generation without increasing installed generation or demand response in ERCOT. The commission can avoid this wealth transfer and achieve the incentive objective of the scarcity pricing mechanism by increasing the HCAP over a period of three years that roughly corresponds to the time period needed for development of new peaking generation and is well beyond the time needed for implementation of new demand-response programs. Accordingly, the commission declines to amend the rule as requested.

5. <u>Timing of the Annual Resource Adequacy Cycle</u>. The commission seeks comment on the start date of the Annual Resource Adequacy Cycle. Proposed §25.505 has the start date as January 1 of each year. Other start dates the commission is considering are October 1, March 1, and May 1. Another alternative being considered is to enforce the low system-wide offer cap whenever the Peaker Net Margin for the previous 365 days is equal to or greater than $150,000 per megawatt and reinstate the high system-wide offer cap when the Peaker Net Margin for the previous 365 days drops below $75,000 per megawatt. Please state your preference for the start date and the reason for your preference. In particular, the commission seeks comments on the impact of the start date

on the level and timing of scarcity pricing in the summer months and resource availability during extreme weather events in the winter months.

Reliant and STEC believed that the commission should not use an annual resource adequacy cycle. Joint Commenters and NRG believed that the entire approach is unworkable and should be replaced with a four-year cycle with a Peaker Net Margin of $350,000 per MW. Joint Commenters and NRG believe that the proposed rule's mechanism would not ensure adequate capital recovery, and LSEs would have no incentive to hedge.

TXU Wholesale suggested using a 365-day rolling basis and suggested language to implement such an approach. According to TXU Wholesale, the rolling-basis would avoid the potential for artificially imposed price oscillations at the start of a new calendar year and would allow for some smoothing so that generation entities can account for the substantial operational uncertainties faced by peakers in the timing of their revenues and profits, because a peaker can go for a substantial time without operating. With regard to the commission's alternative proposal for rolling annual HCAP and LCAP system-wide price caps, there is no economic analysis to support the price levels it has chosen that trigger the cycle between HCAP and LCAP. TXU Wholesale also suggested a change in the threshold to shift the offer cap from HCAP to LCAP. TXU Wholesale stated that the price level that triggers the shift between the LCAP and HCAP should be based on realistic peaker costs, and that the price level that reinstates HCAP on a rolling basis should be increased from $75,000 per MW to $85,000 per MW. ARM replied to TXU Wholesale's proposal by stating that the commission should reject it.

TEC supported an October 1 start date for the Annual Resource Adequacy Cycle, as this date would capture the most recent summer peak for all utilities, while additionally measuring the last full winter of historical record. Austin Energy recommended that resource adequacy be taken up in the summer or fall outside the peak season to give ERCOT a better view of the reserve margin closer to the peak. ARM believed that an October 1 start date would risk exhausting the HCAP envelope before the next summer peak.

CenterPoint recommended that May 1 be used as the start of the Annual Resource Adequacy Cycle, as this date would align the SPM with the summer months and avoid the situation where the LCAP might be triggered during the summer peaking months. CenterPoint believed that the May 1 date would also promote system reliability by encouraging generation to remain on-line during the summer high demand periods. ARM stated that a start date of March 1 or May 1 would risk exhausting the HCAP envelope prior to the months of January and February when the combination of cold weather fronts and plant maintenance outages can create transitory supply-demand imbalances that would precipitate high market prices for balancing energy.

ARM supported the proposed January 1 start date for the annual resource adequacy cycle. The start date would ensure that there would be ample dollars in the HCAP envelope to cover any unusual events from January and February cold fronts that reach Texas while leaving sufficient room in the envelope to provide the required HCAP price signals during the critical summer months.

ERCOT suggested that a start date of May 1 for the Annual Resource Adequacy Cycle due to the number of end-of-year reports and other year-end activities ERCOT must already complete early in the year. ERCOT would be able to incorporate data relating to the cycle in its annual Capacity, Demand, and Reserves (CDR) Report it produces in May of each year.

Commission response

The resource adequacy rule seeks to balance two competing concerns: providing generation and load resources a reasonable opportunity to cover their fixed costs over time and protecting load from excessive transfers of wealth to generators during periods of low reserve margins. Sustained high prices, or the potential for sustained high prices, are intended to serve as a signal that more generation is needed in ERCOT or within a region of ERCOT. However, because the vast majority of loads currently have a very limited ability to see and respond to price signals in ERCOT spot markets in the short run, they do not have the ability to protect themselves from the high prices that may occur. The annual resource adequacy mechanism is intended to protect loads from persistent high prices, while providing sufficient high-price signals to entice new generation into the market.

The commission recognizes that some peaking resources need the opportunity to recover more than an annualized average of fixed costs in a given year because peakers will have limited opportunities to earn scarcity prices in years when reserve margins are large. The rule, as amended, has set the PNM to allow more than twice the annualized fixed costs of a new gas-fired peaking unit, and the offer cap is set high enough to allow new gas-fired peaking generation to meet superpeak load. These provisions, along with the elimination of

MCSM, provide a greater opportunity for cost recovery than exists under the current $1,000 offer cap. The commission is setting the LCAP at a high enough level to allow additional fixed cost recovery during the years when the reserve margin is thin. Taken as a whole, the rule provides generators with an opportunity to earn a reasonable return on their investment.

The four-year approach by advocated by Joint Commenters and NRG would lead to excessive transfers of wealth from load to generators during years of low reserve margins by significantly increasing the total amount that can be collected before the protection provided by the LCAP is initiated. This approach provides additional benefits to generators but undermines the commission's other goal of protecting customers from excessive wealth transfers. The commission believes that the resource adequacy cycle as amended provides the best balance between enhancing the opportunity for resources to recover their costs for new peaking generation and protecting loads from excessively high prices for extended periods.

The commission agrees with ARM's reasons for keeping the start date for the annual resource adequacy cycle as January 1 and declines to change the date in the rule as suggested by TEC, CenterPoint, and Austin Energy. The commission believes that having the offer cap set at HCAP during the first half of each year is important to help ERCOT assure sufficient availability during the winter heating season and the spring "shoulder" season when many plants are scheduled for planned maintenance. Since the opening of the wholesale market in 2001, ERCOT has experienced a number of days during these seasons

when demand approached, or even exceeded, available supply. The commission believes that having a high offer cap during these seasons is critical to allowing the market to maintain sufficient supply through the pricing mechanism. The possibility of high prices in the ERCOT-real-time market provides generation with strong incentives to be available on short notice. It also provides load with strong incentives to voluntarily curtail on short notice to save money. These markets signals impact supply since generators have a great deal of discretion in scheduling planned outages at ERCOT.

The commission notes that the start date of the resource adequacy cycle simply resets the PNM and has no other impact on the ERCOT workload or reporting requirements. The timing of the annual resource adequacy cycle should be set with consideration of the impacts on the market and resource adequacy. In this situation, ERCOT administrative requirements are a secondary consideration. The commission therefore declines to amend the rule as suggested by ERCOT.

The commission also declines to amend the rule as suggested by TXU Wholesale because it would add unnecessary complexity to the determination of what cap is in effect. Further, under TXU Wholesale's proposal, in certain years the LCAP has a non-trivial chance of being the prevailing offer cap during the first half of that year and would not address the concerns with the winter and spring seasons noted above.

6. Resource Adequacy Backstop. The commission seeks comment from ERCOT and other parties on the circumstances and timing of events that may trigger the implementation of

the procedures in §25.505(j), as well as other possible resource adequacy backstop mechanisms than the one described in §25.505(j). Please describe any alternative in detail, provide the rationale for preferring the alternative approach, and provide rule language that the commission could use to implement the alternative.

Nucor suggested that the ELR program should be implemented now and should be considered an integral and ongoing part of the ERCOT system. CenterPoint supported the ELR program to the extent that it is implemented within the criteria established by the ERCOT Generation Adequacy Working Group in 2005. The criteria include participating loads' availability at system peak and measurement and verification of deployments. Joint Commenters stated that if the ELR is adopted, the market power rule should be revised to apply to load resources as well as generation resources.

TIEC stated that the commission should be cautious when implementing any program that is outside the normal market structures. ELR contracts have this character, and in many ways resemble reliability must run (RMR) contracts. New RMR contracts trigger an exit strategy analysis to determine whether there is a cost-effective option to eliminate the non-market contract. TIEC believed that this type of safeguard should be applied in the ELR context. Reliant, in its reply comments, agreed.

TXU Wholesale stated that the backstop mechanism should be a last alternative mechanism in an energy-only market so that scarcity signals created by higher prices and a lower reserve margin are not dampened. In order to preempt ERCOT from procuring these options contracts with load when there is still sufficient capacity in the market, the commission should add a provision requiring ERCOT to enter into emergency load response contracts only when its Medium-Term PASA predicts a reserve margin in the third year of less than 5%.

LCRA and ARM supported the use of ELR contracts as a backstop to ensure reliability under an energy-only resource adequacy mechanism.

ARM replied that it is prudent to retain the proposed ELR backstop mechanism in the resource adequacy rule, provided it is limited in scope and duration and does not become a substitute for the normal operation of the competitive energy market. ARM stated that having a backstop mechanism in the rule to provide customers with an assurance that the commission will act to preserve system reliability under extraordinary circumstances is reasonable. If the ELR contracts are deployed only during system reliability emergencies and not used to mitigate high prices, and the duration of such contracts is capped at one year, ARM continued, the limited scope of the resulting market intervention is unlikely to interfere with true scarcity pricing. ARM and LCRA recommended that ELR contracts either be designed with a strike price equivalent to the HCAP, or have the commission require that the contracts operate as price takers in the ERCOT energy market.

ERCOT, in its reply comments, stated that given that ERCOT instituted its Emergency Electric Curtailment Plan (EECP) on April 17, 2006, and was forced to instruct firm load curtailments for the first time in more than sixteen years, ERCOT sees great value in having access to a voluntary and compensated last line of defense against rotating outages. ERCOT requested that the commission provide the following clarifications in the final rule language.

- Clearly instruct ERCOT stakeholders to complete development of the program and submit it to the ERCOT Board for approval by a date certain. ERCOT suggest a deadline of one year from the effective date of the adopted rule.

- Empower ERCOT to develop and maintain, as part of the ERCOT Protocols, the methodology for triggering the issuance of ELR contract requests for proposal.

ARM and ERCOT suggested that the subsection should define the criteria for the use of the PASA as a benchmark for ELR contracts. ARM proposed that a need for ELR contracts would be established when the medium-term PASA shows for three consecutive months that an ERCOT transmission zone will experience a shortfall in capacity resources for a future delivery period. The backstop mechanism would apply only to the portions of the grid where there is evidence of a persistent supply shortfall. ARM also suggested that the rule should clarify that the commission would make the decision to implement ELR contracts.

ERCOT suggested that the decision be based on the results of a LOLP analysis. ERCOT suggested that for purposes of ELR contracting, if an LOLP study showed a greater than one-in-ten-years chance of a supply shortage for the upcoming year, then ERCOT would initiate the ELR program to acquire sufficient resources to reduce the LOLP to at or below the once-in-ten-years level.

ARM replied that it does not oppose the proposed use of an LOLP analysis to trigger the initiation of the ELR backstop mechanism, provided that the forecasted time horizon is limited to one year. To ensure success of the energy-only market, it is critical that the backstop mechanism be deployed only when it is clear that scarcity prices have not elicited adequate resource additions from the market. Any time horizon for the LOLP analysis in excess of one year would result in premature and excessive ERCOT intervention in the energy-only market and would not give market participants adequate time to respond to anticipated capacity shortages with their own resource additions prior to the initiation of the ELR program.

CPS Energy, in its reply comments, noted that one critical component of any LOLP analysis is the projection of firm demand. In an energy-only market, firm demand is the demand that is unwilling or incapable of curtailing prices up to the applicable offer cap. CPS Energy questioned the ability of anyone, including ERCOT, to produce an accurate forecast of firm demand in this context at this stage in the development of the competitive wholesale market. CPS Energy and NRG stated that ERCOT is more likely to over-estimate than under-estimate firm demand and would unnecessarily procure ELR contracts. CPS Energy also argued that there would be many uncertainties that will challenge ERCOT's ability to produce an accurate forecast of supply, such as future status of mothballed capacity, DC ties, switchable energy, wind capacity, and new capacity.

Reliant, Joint Commenters, and NRG stated that the ELR should not be adopted. Joint Commenters suggested eliminating the ELR provisions of the proposed rule, as they believed that it would pose severe risks to the objectives of an energy-only market yet would not ensure reliability. Joint Commenters deemed capacity payments to load "unfair" to generators, who compete with LaaRs, and was the wrong way to encourage load participation. In reply comments, Joint Commenters expressed concern that the proposed ELR provisions did not establish standards, contract terms and conditions that would require careful public scrutiny.

NRG stated that the ELR proposal would add another level of regulatory uncertainty, would provide load with a capacity payment, and would further mitigate the market in a way that would reduce investment in new generation.

Reliant proposed that if the reserve margin, as projected in the medium-term PASA, falls below the 112.5% threshold, the commission should initiate a proceeding to determine whether expected demand response will be sufficient to address resource needs by the beginning of the fourth year. If the commission determines that an appropriate level of demand response cannot be present within four years, then the commission should implement Reliant's proposed capacity-and-energy mechanism to ensure resource adequacy.

In its reply comments, ARM strongly opposed Reliant's proposal, and recommended that the commission reject it and preserve the ELR contract backstop mechanism. ARM opined that Reliant's recommendation, in conjunction with its proposal to preserve the existing $1,000 per MWh system-wide offer cap, is a backdoor and thinly veiled attempt to force the commission to adopt an installed-capacity market for ERCOT, which the commission considered and rejected last year in favor of an energy-only resource adequacy mechanism. ARM stated that if resource adequacy has not been adequately addressed under the energy-only market it adopts in this rulemaking proceeding, then the commission should retain the flexibility to consider a broad range of options to remedy any shortcomings. ARM stated that there is no legitimate reason to restrict the commission's flexibility on this important issue by requiring it do default to an ICAP market design that the commission already has rejected.

In its reply comments, CPS Energy proposed as an alternative to ELR contracts what it calls the Market-Based Emergency Load Response program (MBELR). Under the proposal, ERCOT would solicit commitments from loads to provide standing offers during the peak hours of the coming year at increasing levels, with the possibility of raising the offer cap to $10,000 per MWh. ERCOT could stratify the quantities solicited at each successive pricing level by applying varying levels of maximum number hours of curtailment per year associated with the commitment.

In their reply comments, Joint Commenters stated that the ELR can only work if it is essentially indistinguishable from price responsive demand in that it does not receive a capacity payment and could set the market-wide clearing price. Joint Commenters provided two alternatives.

- Providing load resources a higher bid cap than generation resources and allowing load resources, if curtailed, to clear the market.

- Integrating reserve scarcity into energy prices through an administratively set demand curve for reserves. Under a zonal market, the real-time cap should be raised to VOLL during any day when there is ancillary service deficiency.

Occidental suggested that the commission a provision to require that ELR be based on the technical reliability needs of the ERCOT system in the most cost-effective manner and be non-discriminatory with respect to any load resources.

TXU Wholesale stated that the backstop mechanism should be a last alternative mechanism in an energy-only market so that scarcity signals created by higher prices and a lower reserve margin are not dampened. In order to preempt ERCOT from being overly conservative in procuring these options contracts when there is sufficient capacity in the market, the commission should add a provision requiring ERCOT to enter into emergency load response contracts only when its Medium-Term PASA predicts a reserve margin in the third year of less than 5%.

Nucor, in its reply comments, stated that the rolling blackouts in April underscore the need for an ELR program. It said that the 5% reserve margin standard suggested by TXU Wholesale to trigger the institution of an ELR program would court potential disaster unnecessarily. Nucor also noted Reliant's proposal that the commission institute a proceeding to determine a response when presented with PASA data forecasting a small reserve margin four years distant, opining that it would complicate the implementation of the ELR concept. Nucor, in its reply comments, recommended that the commission reject both ideas.

ERCOT stated that the ELR program seems unlikely to match up well with mass market participants or aggregated loads – the currently untapped segments of the ERCOT market for load participation. ERCOT stated that mass market or aggregated loads tend to have lower load factors, with peak usage more closely aligned with system peaks than industrial loads.

Comverge stated that the current rules in ERCOT do not facilitate or adequately address the participation of residential and small commercial customers in the resource markets. Comverge stated that the most successful demand response programs for residential and small commercial customers are direct load control (DLC) programs. Comverge posited that a fully out-sourced demand response program can be structured as a power purchase agreement and that the proposed rule should be structured to encourage REPs to enter into these programs. Because such DLC programs are capital intensive, the provider of the program needs to enter into long-term agreements with REPs with a minimum ten-year term. Comverge suggested that as part of the ten-year studies under the SOO, ERCOT should enter into ELR contracts with providers of residential and small commercial demand response programs for a term of no shorter than ten years.

Reliant, in its reply comments, stated that Comverge's proposals would be extremely invasive on REPs and their contracts with retail customers, and even worse, the proposal for ERCOT to contract directly with customers puts ERCOT into a role that properly belongs to REPs. Reliant stated that such regulatory mandates should be rejected.

ARM replied that the commission should reject proposals to extend the term of ELR contracts beyond one year. ARM stated that the goal of an energy-only resource adequacy mechanism should be to encourage voluntary demand-response and generation resource additions through market-based signals, and therefore the scope of the ELR contract should be limited.

ERCOT noted that depending on how the ELR program is designed, loads may find it more desirable to migrate from voluntary load response to the ELR. ERCOT asked the commission to consider whether an unintended consequence of the ELR program could be an increase in uplifted costs to market participants and a decrease in non-emergency-related price responsive load.

LCRA stated that an important feature of ELR contracts is the offering of ELR resources at the system-wide offer cap. The offering of ELR resources at the system-wide offer cap is important because it would ensure that ERCOT's procurement and deployment of ERCOT resources would not distort the scarcity pricing signal the market needs during that critical period and that ERCOT does not use ELR contracts to lower prices in ERCOT spot markets. Reliant, in its reply comments, agreed with LCRA's concern about having the ELR suppress scarcity pricing.

Austin Energy said that ELR costs should be directly assigned to the market participants who require load response. CPS Energy, in its reply comments, agreed. Austin Energy said it maintains a 12.5% reserve margin in serving its own load and therefore should not be paying for additional resource adequacy costs in the form of ELR. STEC, in its reply comments, concurred. ARM suggested allocating ELR contract costs on a zonal load ratio share basis and exempting a

QSE from the uplift of ELR contract costs if the QSE has sufficient resources or purchased power contracts to cover its zonal load obligations. ARM posited that this allocation method would create strong incentives for load-serving entities to execute bilateral forward contracts to cover their load requirements, which is vital to support the construction of new generation resources and to ensure the success of an energy-only resource adequacy mechanism.

Nucor, in its reply, disagreed with Austin Energy, stating that the creation of a workable ELR program should not hinge on whether costs are uplifted to ERCOT market participants generally, as opposed to those entities that are responsible for a reserve margin shortfall. If an ELR program is to be ongoing, Nucor stated, costs should be uplifted to all market participants, as the conditions that cause system emergencies can and will change.

Commission response

After reviewing stakeholder comments in response to this question, the commission believes that the ELR concept needs further stakeholder input and review before the commission decides how or even if it should be adopted as a backup resource-adequacy mechanism. As a result, the commission has decided not to adopt this subsection. The commission may further consider whether a resource-adequacy backstop is needed and, if so, how it should be structured as a part of Project No. 32853.

Comments on other provisions of proposed §25.504

§25.504(a), Application

OPC was concerned that the language limits the applicability of "market power" to generators. It noted that entities other than generation entities can control generation resources and therefore they would have the ability to exercise market power. Similarly, TXU Cities said the section should apply to all entities, not just generation entities.

EDS recommended the inclusion of load entities in the definition of market power.

TXU Wholesale said "generation entity" should be one that owns and controls resources, to be consistent with PURA and §25.505.

Commission response

The commission declines to make the requested changes. Because the definition of generating entity applies to anyone controlling a generation resource, the rule already addresses OPC's concern about an entity exerting control over a generation resource. The commission does not believe that the definition needs to include loads, given the lack of significant participation by loads. The commission notes that this rule is intended to complement the commission's enforcement activity under §25.503 and PURA §39.157. Determining the need for a market mitigation plan under PURA §39.156 is a separate matter. Therefore, limiting the application of this rule only to those "owning and

controlling" generation capacity, as phrased in PURA §39.156, is not necessary or appropriate for the purpose of this rule because the statute cited by TXU Wholesale is not applicable. The commission declines to change the rule as TXU Wholesale suggests.

§25.504(c), Exemption based on installed generation capacity

The commission received a number of comments on subsection (c) of the proposed rule, which establishes an exemption for certain entities with respect to systemwide market power. OPC objected to the exemption, saying it would constitute a free pass for some entities to behave as they wish and could lead to an exercise of market power. OPC cited Enron's activities in California in 2001 as an example of an entity owning less than 5% of the installed capacity could still wield considerable market power.

Regardless of any exemption, however, OPC and Reliant said that mothballed capacity should be included in any measure of market power. OPC disputed arguments that the six months required to bring a mothballed unit back into the market prevents its use for market power. Most new generating units have at least a two-year construction time, during which a mothballed unit could be brought back on line for the purposes of strategic pricing. Reliant suggested as a criterion any mothballed generating capacity which has not been included in a bona fide offer to the market for a period of at least 12 months.

DME expressed concern about the 5% exemption for market power ERCOT-wide. The commission should address defining local market power and the appropriate level of resource ownership within a smaller market that would allow an exemption from market power. Otherwise the enforcement of local market power would become an ad hoc exercise.

CPS Energy said the commission should modify the exemption to make reasonable adjustments for long-term contractual commitments, as FERC does with its market power screens. Such deductions should be based on the minimum of the monthly maximum obligations associated with such contractual commitments over the coming year. Alternatively, CPS Energy said, a similar protection could be achieved by modifying subsection (e) to permit the use of long-term contractual obligations not indexed to short-term prices to the extent that adjusted capacity is within the 5% threshold.

In conjunction with its proposal regarding the scarcity pricing mechanism in proposed §25.505, NRG proposed eliminating all price caps for entities qualifying for the 5% safe harbor exemption, and using the SPM as a price cap for entities controlling more than 5% of installed generation capacity.

TEC agreed that an exemption for generators with less than 5% ownership ERCOT-wide is needed to protect small sellers from the potential scrutiny under a screen, and that small firms should also be presumed to be free of market power in an intrazonal analysis, as such firms are incapable of profiting by withholding and may not even recognize when opportunities exist.

TXU Wholesale commented that the reference to "installed generating capacity" in the rule should refer to "installed generation capacity" since that is the term that is used in PURA and the commission's rules.

Joint Commenters recommended excluding intermittent renewable resources such as wind power from the calculation, as these resources are uncontrollable. In reply comments, Reliant said wind power should be included to the extent it is included in ERCOT's reserve margin calculations. Currently, wind power is discounted to 2.9% of its rated capability.

Commission response

The commission notes that the 5% exemption is limited to the question of whether an entity has market power on a systemwide basis. Contrary to OPC's concern, it is not a free pass for entities to abuse the market in whatever way they wish. OPC refers to Enron's behavior in California, but the commission notes that many of Enron's illegal activities (failure to fulfill ancillary capacity service obligations, for example) would be violations of ERCOT Protocols or commission rules and subject to enforcement regardless of whether or not market power was present. Furthermore, the exemption is wholly inapplicable to any determination of local market power. The IMM will monitor all entities for local market power and advise the commission of possible violations regardless of the size of the entity.

The commission has established the exemption to respond to fears expressed by small suppliers that they may be found to have market power. The definition of market power

adopted by the commission focuses on the *ability* to control prices or exclude competition. Clearly, at some level, a generating entity will lack the ability to control prices even if it was actively and openly attempting to do so. The commission is persuaded that an entity with less than 5% of the installed generation capacity in ERCOT will be unable to control prices on an ERCOT-wide basis. The entity's attempts to raise prices above competitive levels will be subject to considerable risk that it will simply price itself out of the market, a risk that will increase over time as load becomes more responsive to high prices in the ERCOT spot market.

The commission declines to adopt a definition of local market power at this time. The commission prefers to determine the existence of local market power on a case-by-case basis until it can develop a generally applicable definition of the term that would cover all possible variations in local market power.

The commission disagrees with CPS Energy with respect to adjusting the rule to account for long-term contracts. The exemption only identifies entities that are deemed not to have ERCOT-wide market power. An entity that does not qualify for the exemption is not presumed to have market power. Analysis of the impact of long-term contracts would require an examination of the terms and conditions of the individual contracts. While that evaluation is important for a determination of "market power" in an enforcement case, the time and effort required to review the contracts is not justified for purposes of the exemption. For ease of administration by both the commission and affected market participants, the commission declines to make the change requested by CPS Energy.

With respect to the inclusion of mothballed capacity in the calculation, the commission notes that the rule refers to the standard definition of "installed generation capacity" stated in §25.5: "all potentially marketable electric generation capacity." As mothballed capacity is *potentially* marketable capacity, it is included in the calculation as proposed.

However, the commission is persuaded by Joint Commenters that excluding intermittent renewable resources is appropriate. The basic concern addressed by this subsection is whether a generation owner is large enough to control prices or exclude competition. By their nature, however, resources such as wind power are themselves uncontrollable and therefore impractical for an attempt to control the ERCOT-wide market. Therefore in any determination of whether an entity has market power – which would be the next step for an entity that did not qualify for the exemption – the IMM would take into account specific factors such as uncontrollable renewable resources. The commission is confident that such an analysis would reasonably and consistently exclude uncontrollable renewable resources; therefore it is reasonable to exclude such resources from the initial calculation provided in subsection (c). However, the commission finds that there is little practical difference between discounting these resources to a fraction of their rated capacity as suggested by Reliant, and discounting them completely. The commission therefore amends this subsection to exclude uncontrollable renewable resources from the calculation.

The commission agrees with the comments of TXU Wholesale and has amended the rule to refer to "installed generation capacity."

§25.504(d), Withholding of production

CenterPoint suggested the rule clarify that maintaining units off-line or failure to include a generator in a bid stack without a corresponding maintenance event may be a factor in determining whether an entity with market power has withheld production.

DME said "marginal cost" should be refined to provide assurance to market participants of what the commission believes are legitimate offers as opposed to offers that the commission would consider to be withholding of production.

NRG objected to defining economic withholding as offer prices that are substantially above marginal cost, saying that there is at best an ambiguity and at worst a direct conflict between defining economic withholding as bidding substantially above marginal cost, while at the same time proposing an energy-only market that depends on prices well above marginal cost to function successfully. Instead, NRG said the commission should define economic withholding as whether the bid results in a unit's full output not being utilized, and whether the bid results in prices being maintained above competitive levels (which NRG defined as prices above SPM levels).

TXU Wholesale agreed that it is inappropriate to deem that market power has been abused simply because it bids in excess of marginal cost. There should be a more rigorous evaluation of the market and entity conditions before finding that a generator has withheld production. Factors include availability of generation resources, load forecasts, actual load, outages, and the entity's costs and profitability.

Commission response

The purpose of this subsection is to establish a simple principle to guide enforcement: that pricing above marginal cost (however defined) is not by itself sufficient to constitute economic withholding. The difference between the offered price and marginal cost must be large enough to indicate that an entity was exercising *market power*. The commission will make that determination on a case-by-case basis considering many different factors such as those enumerated by CenterPoint and TXU Wholesale. The commission also believes that the definition of marginal cost may be addressed on a case-by-case basis. The commission does not agree with NRG's argument that the rules are ambiguous and inconsistent. Small market participants will have broad latitude in their bidding strategies. Large market participants will be subject to greater scrutiny, but they will still be able to bid above marginal cost. The commission expects that high prices will be a feasible result, if resources are truly scarce in the market. The commission declines to change this subsection.

§25.504(e), Voluntary mitigation plan

STEC and LCRA said that any power company that owns or controls more than 20% of the generation in ERCOT should be subject to a mandatory mitigation plan. The voluntary mitigation plan in the proposed rule is not in keeping with the Legislature's desire to protect against the exercise of market power in the development of a competitive market.

OPC supported this position, and TEC agreed that a mitigation plan for suppliers identified as having market power should be a mandate, not an option. CPS Energy and TXU Wholesale disagreed, saying that an entity should not be penalized solely for having market power.

TXU Wholesale said the Peaker Entry Test it described in its written comments should be deemed as a safe harbor price benchmark. Including such a defined plan would not limit the commission's or a market participant's ability to develop and implement any other mitigation plan, TXU Wholesale said.

Commission response

The voluntary market mitigation plan contemplated by the rule is separate and distinct from a mandatory market mitigation plan required under PURA §39.156 and §39.157. PURA §39.157(c) clearly requires a market participant to file a market mitigation plan within 60 days of being found in violation of the installed capacity limitation of PURA §39.154. The rule does not alter this requirement. The rule does, however, allow a generating entity to file a voluntary market mitigation plan to assure compliance with PURA §39.157 and commission rule §25.503. The voluntary market mitigation plan does not require a prior finding of market power by the commission, so it should not be confused with a mandatory market mitigation plan ordered by the commission following a finding of market power. The commission declines to require that the mitigation plans

allowed by this rule be mandatory. The commission will require the filing of mandatory market mitigation plans when justified as currently provided by PURA.

Comments on other provisions of proposed §25.505

§25.505(b), Definitions

CPS Energy suggested that a definition of "scarcity conditions" be added to the definitions in this rule. In its reply comments, Joint Commenters noted that the lack of a definition of "scarcity" allowed commenters to use their own definitions.

Commission response

The commission declines to make the changes to the rule suggested by CPS Energy and Joint Commenters for the reasons previously discussed in its response to stakeholder comments on Question No. 4 of the preamble.

CPS Energy noted that subsection (e)(3) places certain obligations on "load entities," an undefined term. CPS Energy asked for a definition of load entity.

Commission response

The commission notes that, contrary to CPS Energy's comments, the term "load entity" is already defined in the rule.

§25.505(c), Statement of Opportunities (SOO)

DME expressed concern about the commission directing ERCOT to prescribe reporting requirements for load entities and their plans for adding new load resources or retiring existing load resources. Many loads consider information, such as that regarding commodity manufacturing and processing, to be proprietary. If a competitor could determine in advance that the company was planning to enter a new market region, expand operations within that region, or close operations within that region, it might allow competitors to exploit this information. NRG wanted language inserted that all information submitted to the SOO was considered confidential. ERCOT supported the proposed language prescribing reporting requirements for load entities to report to ERCOT their plans for adding new load resources or retiring existing load resources. In addition, the information from QSEs relating to load resources in their portfolios that are participating in voluntary load response will enhance ERCOT's ability to produce the most accurate SOOs possible.

Commission response

The rule does not require load information as detailed as suggested by DME. It only requires load entities to provide information to ERCOT about load *resources*. This limits the requirement to how the entity plans to participate in the market as a *provider* of energy or capacity services. (As a consumer, the entity will be aggregated with all other consumers in ERCOT's assessment of projected needs.) Because participation as a load resource is voluntary, a load entity can "exit" the ERCOT energy or capacity market without effecting any change to its core business. The rule does not require that the information be provided

to the public or to other market participants; this disclosure will continue to be governed by the ERCOT Protocols. The commission anticipates that the final information provided in the SOO will be sufficiently aggregated to prevent disclosure of load-specific resource planning. Any concerns about confidentiality of information can be addressed by market participants during the ERCOT Protocol revision process. The commission does not see a need to modify the rule language in response to DME's comment.

CenterPoint suggested that language be added to instruct ERCOT to use existing information already being provided by market participants and to prescribe additional reporting requirements, as needed.

Commission response

The commission assumes that ERCOT will use existing information being provided by market participants if doing so meets the requirements of this rule and is cost-effective but believes that the rule language should not restrict ERCOT's ability to collect the information it needs for the SOO. The commission declines to amend the rule as suggested by CenterPoint.

ARM believed that the rule should require a two-year notice period for mothballing or retiring a plant, which would provide the competitive market with sufficient lead time to replace the retired or mothballed generation to preserve system reliability. ARM believed that a shorter notice period would create potential opportunities for generation owners to manipulate the market through strategic retirement or mothballing of generation resources.

TXU Wholesale replied that the two-year notice for mothballing or retiring generation is unworkable. Economic and reliability conditions can change considerably in an electricity market in the course of two years. Furthermore, if a generator were bound legally to a schedule in mothballing or retiring a unit, the owner could be driven into bankruptcy by operating the unit without sufficient cost recovery

Joint Commenters, in their reply comments, suggested that ARM's proposal would be excessive and unreasonable, and therefore should be rejected. Decisions on whether to retire or mothball a generating unit are vital to the owner's ability to manage its assets and risk and are based on operational needs and the market. Notice two years in advance would impact generators' ability to control their costs and manage their assets in a way that would likely deter new investment. Joint Commenters noted that the appropriate notice period for retirement or mothballing of a unit was considered and decided by the commission less than 18 months ago, when it established a 90-day notice period.

Commission response

The commission agrees with TXU Wholesale and Joint Commenters that ARM's suggestion to require a two-year notice period for mothballing or retiring a plant would be unworkable and would hinder the owner's ability to manage its assets and risks. Such restrictions on market exit would make market entry of new generation less appealing and could increase the costs to load in the long run. As a result, the commission declines to amend the rule as suggested by ARM.

Joint Commenters stated that similarly, a decision to winterize a plant must be made on far more current information, but under §25.502(f) of the commission's rules, and ERCOT Protocols Section 6.5.9.1, winterizing is considered mothballing.

Commission response

The commission believes that ERCOT and its stakeholders can address this issue through the protocols development process and declines to address the issue in the rule.

§25.505(d), Projected Assessment of System Adequacy (PASA)

CenterPoint suggested adding the following to the list of information published in the PASA: forecasts of generation, import capability, and reserve using NERC planning criteria by ERCOT zone or area. CenterPoint also recommended that voltage and reactive requirements by ERCOT zone or area be included in the PASA.

Commission response

The commission believes that the suggestions from CenterPoint could provide the market with a more complete and useful set of information. However, the commission cannot at this time judge the costs and benefits of including the information that CenterPoint recommended. The commission declines to amend the rule as suggested by CenterPoint but believes that stakeholders can work with ERCOT to determine see if such information is cost-effective to include in a PASA.

ARM suggested that all PASA data components be reported in the PASA on a zonal basis.

Commission response

The commission agrees with ARM that aggregated resource information should be reported in a PASA on a zonal basis to provide more information and transparency to the market and amends the rule accordingly.

ARM suggested that the Medium-Term PASA reflect planned retirement or mothballing of resources in addition to planned maintenance outages, which would ensure that the Medium-Term PASA provides a more realistic picture of future supply-demand conditions to market participants and reduce opportunities for market manipulation through the strategic withholding of capacity resources.

Commission response

The commission assumes that ERCOT will take into account the retirement and mothballing of resources in its Medium-Term PASA. The commission, however, wishes to give ERCOT the flexibility to determine which resources are likely to be mothballed or retired rather than fixing criteria in this rule.

ERCOT stated that the critical tasks necessary to develop a Medium-Term PASA, including developing linkages between existing systems and modifying existing processes, will require significant incremental increases in ERCOT human resources. ERCOT urged the commission to consider whether the value of the Medium-Term PASA over the value provided by the proposed SOO would justify the additional ERCOT resource requirements. Reliant, in its reply comments, concurred.

TXU Wholesale suggested eliminating subsection (d)(1)(D). TXU Wholesale stated that it is impractical to identify three years in advance the availability of future resources due to outages or scheduled maintenance. TXU Wholesale stated that information that is so speculative is, at best, minimally useful to the market, and at worst, dangerously misleading. Providing such information three years in advance has minimal usefulness to the market. Reliant disagreed with TXU Wholesale in its reply comments, stating that this information is critical to ensure resource adequacy.

ARM urged the commission to require ERCOT to publish both the SOO and the Medium-Term PASA, as ARM believed the Medium-Term PASA provides incremental value over the SOO. ARM stated that one of the most important building blocks of a successful energy-only resource market is the dissemination of adequate information to the market regarding projected resource needs. This information, according to ARM, allows market participants to construct resource additions with a sufficient lead time to meet the requirements of the region.

ARM stated that while the SOO provides such information for a long-term horizon of five to ten years, the additional value of the medium-term PASA is that it provides projected resource adequacy data over a three-year timeframe that is more closely linked to the time horizon for the addition of new peaking generation capacity. Moreover, the Medium-Term PASA is designed to provide more detailed system data relative to the SOO, including projected loads and resources disaggregated by ERCOT zone and anticipated transmission constraints. Finally, the Medium-Term PASA would be published on a monthly basis, giving market participants more current information than the SOO, which would be published annually.

ERCOT supported the proposed language prescribing reporting requirements for load entities to report to ERCOT their plans for adding new load resources or retiring existing load resources, in part because the information from QSEs relating to load resources in their portfolios that are participating in voluntary load response will enhance ERCOT's ability to produce more accurate Medium-Term PASAs.

In its reply comments, ERCOT stated that the biggest challenge would be including information about planned outages into the projection of transmission constraints. If the requirement were removed, the development of the Medium-Term PASA is achievable. With respect to the Short-Term PASA, ERCOT agreed that the planned outage information would provide value but would require ERCOT to develop automated systems that would either feed data from the outage scheduling system into the market forecasting model or expand the day-ahead calculation of transmission limits planned for implementation as part of the nodal market to seven days. Either option is feasible, but only with systems that are being developed as part of the nodal market design. Accordingly, ERCOT recommended eliminating the term "planned outages" in subsections (d)(1)(C) and (d)(2)(C), and adding a new subsection (d)(1)(E) instructing ERCOT to file a plan by October 1, 2006, for completing a project that would incorporate planned outage data into the Short-Term PASA upon nodal market implementation.

ERCOT stated that the provision of aggregated information on the availability of resources also will change ERCOT's system and internal processes, primarily to combine information on future levels of installed generation with information on resource outages.

Commission response

The commission disagrees with TXU Wholesale's suggestion to eliminate the Medium-Term PASA. As ARM and Reliant stated in their comments, market participants need the information provided in the Medium-Term PASA to help meet their resource adequacy needs. The commission agrees that the Medium-Term PASA provides valuable information to market participants and declines TXU Wholesale's proposal to amend the rule by eliminating this section. The commission also finds that ERCOT's concerns have merit. The commission realizes the resource limitations confronting ERCOT staff during the implementation of the nodal market. The commission will work with ERCOT to minimize the work needed to provide market participants with the information required in this rule. For instance, the commission finds it acceptable if ERCOT can meet the data posting requirements with a minimum of post-processing of the data. Therefore, the commission has amended the rule language according to ERCOT's suggestions in its reply comments.

Reliant suggested that the Medium-Term PASA project conditions for the subsequent four years rather than three years. ERCOT replied that adding another year to the outlook would potentially cause the PASA to produce misleading results because of the limited accuracy of information four years out.

Commission response

The function of the Medium-Term PASA is to provide market participants with information on the availability of planning reserves up to three years in the future. With respect to Reliant's suggestion to extend the Medium-Term PASA to four years, the commission finds ERCOT's reply persuasive and therefore declines to make the change suggested by Reliant.

ERCOT anticipated the need for substantial stakeholder discussion in order to develop protocols that will prescribe how to integrate the details of the short-term PASA and those of the medium-term PASA. Reliant suggested eliminating the Short-Term PASA, because the Short-Term PASA was duplicative of the Medium-Term PASA.

Commission response

The commission declines to eliminate the Short-Term PASA, as the information reflects the availability of operating reserves for the next week, which is different from the information provided in the Medium-Term PASA. The commission agrees with ERCOT's assertion that stakeholder discussion and input will be needed to complete successfully the integration of the Short-Term PASA and Medium-Term PASA. The commission requests that ERCOT keep the commission informed on a timely basis on the progress and timetable associated with this integration.

TXU Wholesale suggested eliminating this subsection (d)(2)(D). TXU Wholesale stated that revealing information to the market on resource outages will only increase the ability of other market participants to impact prices through strategic behavior. Because of the small size of certain ERCOT zones, TXU Wholesale believed, revealing aggregated information regarding resource outages will reveal specific outage information for certain generators. When participants know that specific supply will be constrained by outages, they have the information necessary to manipulate their own generation availability in a manner that exacerbates the problem of reduced supply and causes an overall artificial increase in prices. Reliant disagreed with TXU Wholesale in its reply comments, stating that this information is critical to ensure resource adequacy.

Commission response

The commission disagrees with TXU Wholesale's assertion that providing aggregated information on resource availability will harm the market. Providing resource information up to seven days in advance allows market participants to have a clearer picture of the amount of planned outages. Owners of generation have great discretion in scheduling planned outages, including changing the timing of those planned outages. As a result, providing aggregated resource information to market participants allows them to more easily bring generation or load resources into the market if the projected resources are not sufficient to meet demand. The commission finds the value of providing market participants with aggregated data on resource availability greatly outweighs any concerns

about potential misuse of that information. As a result, the commission declines to amend the rule as TXU Wholesale has proposed.

§25.505(e), Filing of resource and transmission information with ERCOT

ERCOT supported the timely advance provision of the information required in this subsection, which will increase ERCOT's ability to meet reliability requirements and enhance the market's ability to respond to outages without ERCOT intervention.

CenterPoint suggested that language be added to instruct ERCOT to use existing information already being provided by market participants and to prescribe additional reporting requirements, as needed. CenterPoint suggested adding language that would explicitly state that the information would be incorporated into the SOO and PASAs. NRG wanted language inserted that all information submitted to meet this requirement was considered confidential.

Commission response

The commission believes that ERCOT will work with stakeholders through the protocol development process to ensure that the concerns expressed by CenterPoint and NRG are considered and addressed. The commission does not find it necessary to amend the rule as suggested by CenterPoint or NRG.

Reliant recommended that subsection (e)(3) be modified to require reporting of unavailability rather than availability and have the commission order ERCOT to enhance ERCOT's outage scheduling to allow LaaRs to provide outage scheduling information. ERCOT, in its reply, recommended using the ERCOT stakeholder process to consider the value of adding load resource outages into ERCOT's outage scheduling system.

Commission response

The commission does not see the benefit of making the change that Reliant has suggested and declines to amend the rule accordingly. The commission agrees with ERCOT and suggests that Reliant use the ERCOT stakeholder process to address its concerns about adding load resource outages into ERCOT's outage scheduling system.

CenterPoint recommended that generation entities file their gross MW and MVAR dependable capacity in addition to net dependable MW capability.

Commission response

The commission declines to amend the rule as suggested by CenterPoint but recommends that stakeholders work with ERCOT to determine if including this information is useful and cost-effective for ERCOT in developing the reports required by this rule.

CPS Energy noted that subsection (e)(5) has a requirement that LSEs provide "complete information on load response capabilities pursuant to bilateral agreements between LSEs and their customers." CPS Energy believed that the term "load response capabilities" and the intended scope of the term "complete information" need to be clarified.

Commission response

The commission believes that ERCOT needs to continue to improve its load forecasting methodologies. Information from load resources is an important part of such forecasts, particularly as more demand-side resources become available in ERCOT. The commission believes that ERCOT is in the best position to determine what specific information it needs to estimate and forecast price-responsive load. The commission expects that ERCOT will work with stakeholders through the protocol development process to clarify the issues that CPS Energy has raised. As a result, the commission does not find it necessary to amend the rule as suggested by CPS Energy. The commission clarifies the rule by indicating that the information should include self-arranged supply as well as bilateral contracts.

§25.505(f), Publication of resource and load information in ERCOT markets

See discussion of Question 2, disclosure of disaggregated data.

§25.505(g), Credit standards for qualified scheduling entities

See discussion of Question 3, credit requirements.

§25.505(h), Improving price responsiveness of load

Joint Commenters supported this subsection as written.

Various Parties stated that the impact of the proposed rule language in this subsection is limited due to a narrow focus on demand profiling. What is lacking is any coherent program to encourage widespread adoption of demand response, load management, and price-responsive demand. With the onset of the new nodal market structure in 2009, and the gradual increase in the cap on balancing energy prices, Various Parties stated that is important to develop stabilizing mechanisms in the electricity market that may dampen extreme price spikes.

Various Parties noted that demand response includes a far wider spectrum of responses to prices and incentives that should be investigated. Various Parties noted that current technology allows the aggregation of commercial demand into blocks that are controllable and highly responsive, and that could be potentially dispatched as an operating reserve.

Various Parties noted that prior to restructuring, the ERCOT utilities reported over 3,100 MW of interruptible load in ERCOT. Many direct load control (DLC) programs and group load curtailment programs that existed prior to restructuring are no longer in operation. Various Parties suggested that the rule make a strong statement in support of all demand-side programs, and proposed the establishment of a series of pilot programs and initial studies that could provide information to the commission to support a separate rulemaking to determine the optimal policies to encourage the development of price responsive electricity demand in Texas.

Various Parties stated that because there is a cap placed on the amount of interruptible load that can provide responsive reserves, there is essentially a “waiting list” of more than 500 MW of load than could be interrupted without notice. These loads cannot curtail at ERCOT’s request because there is no program or market mechanism available to permit them to participate. EDS noted some clear and substantial barriers in the current market design that dramatically limit load participation and that loads, as a practical matter, have only two programs from which to choose if they wish to participate as a demand-side resource in ERCOT: Responsive Reserve Service and Non-Spinning Reserve Service.

EDS noted that industrial loads have strong incentives to retain the voluntary option of responding to prices as they occur rather than committing ahead of time for little or no added financial gain under the Balancing-Up Load (BUL) program. EDS encouraged the commission to direct ERCOT by the end of the year to review the BUL program, identify the causes for the lack of participation in the program, and suggest improvements to the program that would substantially increase participation and reduce energy prices.

EDS noted that loads are currently excluded from participating in Replacement Reserve Service and balancing energy service (BES) because further system changes are required, and a timeline for completion has not been set. EDS highlighted that the BUL program suffers from major design flaws that make it unusable. Reliant, in its reply comments, stated that the BUL program should not be fixed, as it would not carry over into the nodal market design.

Various Parties stated that ERCOT planners and operators need to know when a market-based curtailment or load response will be triggered as well as their impact on resource requirements. Various Parties stated that under criteria jointly established by ERCOT's Generation Adequacy Task Force and the Demand Side Working Group, a load that is simply curtailing on its own volition when prices rise does not qualify as an adjustment to a reserve margin. These criteria may need to be altered so that the value of ELR contracts may be recognized as a reserve margin adjustment and reliability resource.

Good Company stated that an energy-only market does not encourage demand response or energy efficiency *per se*. An energy-only market requires higher prices, especially during peak hours, and the ability of load to benefit from responding to those higher prices, which will encourage demand response and energy efficiency.

Various Parties stated that a token or nominal incentive payment to load for the additional costs and obligations associated with formally bidding a response to the market is needed to entice them to make such a formal commitment. If the incentive payment is too low, then the load will passively respond to high prices, which ERCOT will find difficult to detect in forecasting load and has limited use for ERCOT's system planners and operators.

Nucor stated that it is absolutely necessary for ERCOT to work with market participants on an ongoing basis to create the necessary conditions for, and remove impediments to, price response by load. Price-responsive loads must be insulated from reliability-unit commitment capacity short penalties for responding to real-time prices. Notice times of at least ten minutes of the applicable zonal or nodal settlement price must be maintained.

Nucor stated that the periodic progress reports on ERCOT's efforts to improve price responsiveness of load was a good approach and suggested that the commission solicit comments on each status report to ensure the broadest input from stakeholders.

Occidental stated that the commission should clarify its intent for ERCOT to work with market participants to create the necessary conditions for, and remove impediments to, *market-based* price response by load. STEC and CPS Energy, in their reply comments, concurred.

Occidental suggested that the commission require the review of the current status of implementation of previously approved PRRs relating to demand response and the incorporation of demand response in the Texas Nodal Market.

Reliant suggested that an evaluation of demand-side response take place before offer caps were raised. ERCOT, in its reply comments, stated that unlike the proposed list of demand-side issues in the proposed rule, which directs ERCOT to analyze the existing market structure to provide a factual basis for discussing key aspects of price responsiveness of load, Reliant's list would mandate that ERCOT draw conclusions regarding the adequacy of the current market and make recommendations to change the market. ERCOT stated that the establishment of a demand-response program involves policy and economic issues that can be addressed only by the commission. ERCOT recommended that the additional items proposed by Reliant not be added to the list but rather deferred to the upcoming commission project on demand response.

Good Company stated that the primary barrier to load shifting by smaller commercial and industrial loads is the lack of "smart meters" that will replace profiling with actual consumption data. Currently, while large industrials can choose time of day or other programs that reward them for shifting consumption from high-cost hours, other customers have little incentive to curtail or shift consumption since they face average rates based on stylized demand profiles. Retailers that use profiles also have little incentive to encourage such behavior with their customers.

In order to fully exploit the potential benefits of demand response, Good Company said, it is important to install smart meters on an almost universal basis, implement demand-response pilot programs, and develop time-of-use pricing programs.

EDS encouraged the commission to direct ERCOT to develop price-responsive programs that will not encourage offerings from REPs but allow non-load-serving QSEs to schedule and receive benefits of price response from loads. EDS also encouraged the commission to review the CenterPoint tariff provision that imposes a $90 per month charge for IDR metering, which EDS considered a barrier to demand-side response by smaller commercial loads.

Joint Commenters, in their reply comments, noted that MCSM lowered the market clearing offers during the period of rolling blackouts on April 17, 2006, which would provide little incentive for voluntary demand response. OPC, in its reply comments, expressed the opinion that allowing prices to rise to the cap on April 17 would not increase new generation investment over time. OPC opined that loads would not hedge against such spikes, choosing to pay the market clearing price instead.

EDS also noted that loads face prices that are often revised downward the next business morning and that loads can't respond to prices when they don't know whether the price will be adjusted later. EDS requested that ERCOT report to the commission on the reliability of its real-time energy prices and establish a minimum threshold of at least 99.9% accuracy. Reliant, in its reply comments, concurred with EDS. ERCOT, in its reply comments, noted that ERCOT posts accurate real-time data, and that the examples EDS lists do not reflect the lack of reliability of ERCOT's posting of data; rather they represent situations where prices were adjusted in a post-hoc manner as required by MCSM.

Good Company suggested that transmission and distribution utilities (TDSPs) be encouraged to establish demand-response programs behind distribution substations that are facing congestion or reliability issues. Reliant, in its reply comments, disagreed with Good Company that TDSPs should be involved with demand-side programs because they are not retailers, and retailers operating in the free market will provide innovative programs when the necessary infrastructure is in place and market conditions are ripe.

Austin Energy supported demand-side participation and recommended that the commission direct ERCOT to provide a report to the commission within six months of the effective date of the rule regarding existing passive demand response. ERCOT replied that a single such study in an evolving market might be inconclusive and would be unnecessary, given the new LSE reporting requirements proposed in §25.505(e)(5). ERCOT noted that this effort will require additional resources at ERCOT, at least through the thirty-month reporting requirement.

CPS Energy stated that the section was too prescriptive and recommended eliminating specific instructions and timelines for ERCOT. CPS Energy said that subsection (h)(2) should be directed to TDSPs. CPS Energy also stated that the accuracy of load profiles with respect to demand-side programs is not relevant, because, by definition, they cannot be used to provide accurate price signals to loads because load profiles do not provide accurate measures of actual consumption for an individual customer on a 15-minute, hourly, or even daily basis. CPS Energy suggested eliminating subsection (h)(1) through (h)(4).

Occidental stated that the commission should specifically order ERCOT to implement PRR 307, *Controllable Resources*, without delay. The protocol revision, which was approved in March 2002, allows load resources to provide "generation type" (also referred to as "AGC-type") ancillary services to the ERCOT market. The PRR would allow load resources that can follow Automatic Generation Control (AGC) dispatch signals from ERCOT and respond continuously to frequency deviations like generation resources, to provide AGC-type ancillary services such as Regulation Up Service, Regulation Down Service, and Responsive Reserve Service.

Occidental stated that implementing PRR 307 would be the easiest and quickest way to improve participation of load resources in the ERCOT market and would make it unnecessary to prorate load resource participation in the Responsive Reserve Service. Occidental stated that implementing this PRR would be a signal from the commission that the process outlined in subsection (h) would not result in delayed implementation of other PRRs related to demand-side resources. Occidental noted that other markets such as PJM and the NYISO will be allowing controllable load resources to participate in AGC-type ancillary service markets in the near future.

EDS stated that loads can not participate in Regulation Up and Regulation Down service because further system changes are required to implement PRR 307 to send AGC signals to loads. EDS noted that implementation of PRR 307 has the lowest priority assigned to any ERCOT project.

Reliant, in its reply comments, disagreed with Occidental, EDS, and others directing ERCOT to make major system changes that will have limited application to only a very few load resources who can meet the technological requirements to provide such service.

ERCOT, in its reply comments, suggested that Occidental should appeal the implementation ranking of PRR 307 at ERCOT rather than ask the commission to implement it as part of a rulemaking.

Commission response

The commission is committed to encouraging greater participation by load resources in the ERCOT market. However, after reviewing stakeholder comments on this subsection, the commission believes that this subject deserves a more thorough review along with other demand-side issues so that a comprehensive commission policy can be developed. Accordingly, the commission has established a new rulemaking project, Project No. 32853,

Evaluation of Demand-Response Programs in the Competitive Electric Market, **to address demand-response programs. Since the issues will be addressed in Project No. 32853, the commission has decided to adopt the rule without this subsection. The commission will further consider the issues stakeholders raised in their comments in Project No. 32853.**

§25.505(i), Scarcity Pricing Mechanism (SPM)

Regarding subsection (i)(1), see discussion of Question 5, timing of the annual resource adequacy cycle. Regarding subsection (i)(6), see discussion of Question 4, considerations in setting the levels of the system-wide offer cap.

Regarding subsection (i)(2), Peaker Operating Cost (POC), TXU Wholesale suggested that the POC parameter should be adjusted upward to account for all of the hypothetical peaker's variable costs of operation (*e.g.*, wear and tear on the peaker from starting the unit, startup fuel costs) and market operating risks. TXU Wholesale recommended using a heat rate of at least 13 MMBtu/MWh based on the regression analysis of its consultant. TXU Wholesale analyzed the heat rates of 158 peaking units that are currently operating in ERCOT and found that heat rates ranged from 9.4 to 18.0, with the mean and median heat rate of a fully-loaded peaking unit being 11.7.

ARM disagreed with the changes TXU Wholesale proposed in subsection (i)(2). ARM noted that the annual PNM limit is designed to provide a sufficient revenue stream for a new conventional combustion turbine, not older existing generation facilities. Therefore, ARM continued, the POC should be calculated based on a heat rate of 10 consistent with the heat rate that would be expected from a new peaking generation facility.

Commission response

The commission agrees with ARM's reply to the TXU Wholesale proposal to raise the heat rate in the POC calculation from 10 to 13. ARM's reply comments accurately represent the commission's rationale in choosing a heat rate of 10 in the POC calculation. In addition, a large portion of the non-fuel operating and maintenance costs that TXU Wholesale listed, such as wear and tear, are related to depreciation, which the commission considers part of the capital costs of replacing a generation unit and is included in setting the PNM. Therefore, the commission declines to amend the rule along the lines TXU Wholesale suggested.

Regarding calculation of the PNM, TXU Wholesale stated that the SPM should account for prices in the bilateral market, not just real-time energy prices at ERCOT and should be calculated on a 12-month, rolling basis. TXU Wholesale suggested using a time-weighted average of prices recorded for each settlement interval in that hour.

ARM disagreed with the changes TXU Wholesale proposed in subsection (i)(4) and urged the commission to reject them. ARM noted that bilateral energy prices are for contracts of various lengths. Mixing energy prices from non-spot bilateral transactions with spot market prices for balancing energy is not appropriate because it will understate the revenue opportunity for resources in the balancing energy market. Moreover, resources that are contracted bilaterally have the ability to capture scarcity rents over their term, as the price for power under such contracts should have been negotiated with the anticipation that the buyer would potentially face very high spot market prices for balancing energy during periods of resource scarcity but for the contract.

Commission response

The commission agrees with ARM's evaluation of TXU Wholesale's proposal to amend the language in this subsection. TXU Wholesale's proposal would result in an inappropriate mixing of bilateral prices and spot market prices. The commission notes that bilateral contract prices are often higher than prices determined in a centralized spot market because of factors such as counterparty or credit risks, the size of the transactions involved, and customized features of the bilateral contract. Bilateral contracts also lack the transparency and widespread participation that are necessary for the SPM to have the confidence of all market participants. In addition, the differences in the terms and conditions of bilateral contracts would make their inclusion in the SPM calculation very complex. For all of these reasons, the commission declines to amend the rule along the lines TXU Wholesale suggested.

Regarding the LCAP, TXU Wholesale stated that its review of units in the ERCOT market that the current proposed levels for LCAP underestimated the long-run marginal costs of a peaker and did not capture changing trends in capital costs and operating profiles of peakers over time. ARM replied that LCAP is not about attracting new construction; it is about ensuring the sustained receipt of monopoly rents does not occur. The LCAP value needs to be set to ensure all generators, regardless of efficiency, have the ability to recover their variable operating costs on a going-forward basis. Otherwise, inefficient generation may not operate, which could lead to involuntary load curtailments, as it is likely a resource adequacy problem would be present if the LCAP value ever came into force.

ARM recommended a lower LCAP than in the proposed rule to stop the receipt of sustained monopoly rents by resources. ARM recommended that the commission adopt an LCAP value equal to no more than 15 times the Houston Ship Channel Index (HSCI) plus a $2 per MWh allowance for non-fuel variable operations and maintenance expenses. The change will ensure that generation resources do not earn sustained monopoly rents after already having the opportunity to earn a sufficient annual contribution to fixed and sunk costs. CPS Energy, in its reply comments, supported ARM's general approach but suggested using an 18 heat rate rather than a 15 heat rate to make sure peaking resources can cover their operating costs.

OPC expressed concerned that the proposed LCAP was set too high. ARM, in its reply comments, agreed with OPC. OPC stated that the LCAP should recognize the improvement in heat rates in gas turbines. OPC advocated that the LCAP be set at ten times the Houston Ship Channel (HSC) gas price index with no other conditions and as long as the HCAP is not changed. The multiplier of ten times should be reviewed annually to reflect efficiency improvements in gas turbines.

OPC believed that the LCAP level seems to greatly exceed any calculation of a price that would cover both marginal costs and some fixed costs, particularly after a peaker has recovered

$150,000 per MW. Therefore, OPC proposed that the LCAP be tied to the heat rate of the most modern peaking unit. ARM, in its reply comments, disagreed with OPC's proposal of using the heat rate of the most modern peaking unit, stating that older, less-efficient units need to cover their operating costs.

Commission response

The commission agrees with ARM's comments that an important purpose of the LCAP is to prevent excessive transfers of wealth from load to generation during years when reserve margins are thin. Allowing excessive recovery would result in an unwarranted transfer of wealth to generators from load, a situation that the commission is attempting to avoid. The other consideration is that it be set at a level that will permit most generating units in the market to operate profitably under the cap. Allowing a minimal recovery above short-run marginal costs for generation would limit demand-side response in the market and reduce the incentives for peaking generation to be available to offer into the ERCOT spot markets. The decentralized unit commitment in the zonal market design likely would exacerbate the problem.

The commission intends to set the LCAP at a high enough level to provide incentives for generation and load resources to be available to respond to shortage conditions in the remaining portion of the annual resource adequacy cycle when the PNM has exceeded the $175,000 per MW threshold. The commission believes that the formula for LCAP strikes the appropriate balance and therefore declines to amend the rule as suggested by ARM, TXU Wholesale, CPS Energy, and OPC.

TIEC noted that virtually every competitive electricity market in the world contains some type of "circuit breaker" to control unjustified price excursions from whatever cause and supported the concept of a circuit breaker to avoid excessive and unjustified transfers of wealth from consumers to other market segments.

LCRA stated that a "circuit breaker" mechanism similar in concept to that used in the Australian market would be beneficial for the ERCOT market. The mechanism would trigger if the PNM in any 168-hour period is $50,000. This mechanism would allow for a "cooling off" period of 168 hours during which the system-wide offer cap would be set at LCAP. LCRA proposed the following revised language for the rule: "If the PNM for any consecutive 168-hour period exceeds $50,000, then the system-wide offer cap shall be set at LCAP for the immediately following 168-hour period."

In its reply comments, OPC supported LCRA's circuit breaker mechanism, which OPC believed would provide protection against unintended or unforeseen consequences of the new rule. OPC noted that the circuit breaker was similar to the one used in the Australian market. In its reply comments, ARM stated that it conceptually supports LCRA's proposed circuit breaker, but believed the dollar amount of the threshold is too low because a substantial portion of a year's resource scarcity may take place in a single week's time (*e.g.*, during an extreme heat wave). ARM proposed a $100,000 per MW threshold for the circuit breaker based on an offer cap of $6,000 per MWh or a threshold of $85,000 per MW with an offer cap of $5,000 per MWh. CPS Energy, in its reply comments, opposed the LCRA circuit breaker because it would prevent the required pricing levels from occurring at all of the times when they need to occur. CPS Energy suggests that the required level of prices be allowed to occur when required as envisioned by the rule.

TXU Wholesale replied that the commission should not adopt a "cooling-off period" or "circuit breaker" for high prices, if those mechanisms are designed so that their operation could mitigate legitimate scarcity prices or deny generators the opportunity to cover long-run costs. TXU Wholesale stated LCRA's analogy to the Australian market's Cumulative Price Threshold (CPT) was misplaced. The temporary price caps in the Australian market are effective only until the end of the trading day on which the CPT falls below the fixed threshold. Thus, in the Australian market, the price threshold is much higher, and the price cap is not artificially sustained for 168 hours.

Commission response

The commission notes that the HCAP in ERCOT is significantly lower than its counterpart in Australia. This factor, along with the fact that the ratio of all-time peak to average summer peak demand in ERCOT is not as high as it is in Australia, reduces the need for a weekly circuit breaker. The commission notes that LCRA's proposed circuit breaker would be tripped at a much lower level than occurs in the Australian market. ARM's proposed level is less invasive, but the commission agrees with TXU Wholesale that an additional weekly circuit breaker could interfere with scarcity pricing in ERCOT and therefore declines to include such a mechanism in this rule.

Joint Commenters opined that the proposed HCAP levels are appropriate but the threshold that would drop the system-wide offer cap from HCAP to LCAP is too restrictive. Joint Commenters recommended a four-year resource adequacy cycle with a PNM of $350,000 per MW with an LCAP trigger when the PNM reaches $300,000 per MW to ensure sufficient revenue opportunities for resources. Also, Joint Commenters noted that the $300,000 per MW reference is to prevent bouncing between HCAP and LCAP on a daily basis.

Commission response

As previously discussed, the commission has determined that the proposal by Joint Commenters to raise the PNM to $350,000 per MW would lead to excessive transfers of wealth from load to generation without any additional benefits to the market. The commission declines to amend the rule accordingly.

ARM stated that the proper selection of the annual PNM, the HCAP and the LCAP is critical ensuring new resource investment is made while protecting consumers. ARM stated that the annual PNM limit must allow gas-fired peaking resources the opportunity to earn a return competitive with the stock market within a three-year recovery period. The return implied with the proposed rule's $150,000 per MW threshold for the PNM is less than 3%, compared to a 12.4% return for "large cap" stocks. Using a 12.4% return on investment as a benchmark and cost information for a conventional combustion turbine, ARM believed that the PNM should be set at $175,000 per MW. ARM suggested that the annual PNM limit be raised from $150,000 per MW to $175,000 per MW to ensure sufficient annual revenue opportunities for resources.

OPC, in its reply comments, opposed any increase in the PNM, which in the rule is set at a level higher than used in the Australian market.

Commission response

The commission agrees with ARM that the $150,000 per MW PNM may be insufficient to allow recovering of capital costs of new peaking generation and amends to rule to raise the PNM to $175,000 per MW.

Regarding IMM review of the SPM, TXU Wholesale suggested changing IMM review from voluntary to mandatory and suggested that the IMM review the HCAP and LCAP in light of the value of lost load and the economics of peaking generation.

Commission response

The commission is aware of the need to monitor the progress of the energy-only resource adequacy mechanism. The commission expects the IMM to review the SPM annually, and will welcome public comment on the IMM's review. The commission, however, believes that a change in the rule is unnecessary and declines to amend the rule as proposed by TXU Wholesale.

§25.505(j), Authority to enter into ELR contracts to maintain resource adequacy

See discussion of Question 6, resource adequacy backstop.

§25.505(k), Development and implementation

ARM stated that the success of the energy-only resource adequacy mechanism will be seriously undermined if market participants believe that the commission will arbitrarily and frequently intervene in the markets to modify critical elements of the mechanism. Therefore, it is vital that the rule clarify that the commission will only override the provisions of the energy-only resource adequacy mechanism as a last resort, and only in response to extraordinary circumstances.

ARM further suggested that the proposed rule should establish procedural requirements that would be met before the commission intervenes in the operation of the mechanism. For instance, a commission decision to take actions inconsistent with the resource adequacy mechanism should be preceded by a public inquiry into the performance of the mechanism, and such an inquiry should give all interested parties an opportunity to express their views. This inquiry could take place as part of the commission's consideration of the IMM annual review of the scarcity pricing mechanism. Joint Commenters, in their reply comments, agreed with ARM's recommendation.

Reliant proposed elimination of the second sentence in subsection (k) because it was too vague. Joint Commenters, in their reply comments, also supported the alternative that Reliant suggested if the commission does not add the sentence quoted above. TXU Wholesale opined that the IMM should review the details of the SPM mechanism annually.

Commission response

The commission agrees with ARM that for the energy-only resource adequacy mechanism to be successful, the commission needs to minimize what the market perceives as arbitrary and frequent intervention in ERCOT markets. The commission also agrees with ARM and TXU Wholesale that public review and discussion at the commission and IMM review of the energy-only resource adequacy mechanism should identify any shortcomings and facilitate the development of improvements to the mechanism. The commission understands the commenters' concerns and amends the rule to state that commission action under this section will be taken to protect the public interest. This standard is consistent with the commission's duty under PURA §39.001 and will provide assurances that the commission's action will not be arbitrary.

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

This amendment and the new sections are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2005) (PURA) which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction and specifically, PURA §35.004, 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, predatory, or anticompetitive; PURA §39.001, which establishes the legislative policy to protect the public interest during the transition to and in the establishment of a fully competitive electric power industry; PURA §39.151, which requires the commission to oversee and review the procedures established by an independent organization, directs market participants to comply with such procedures, and authorizes the commission to enforce such procedures; and PURA §39.157, which directs the commission to monitor market power associated with the generation, transmission, distribution, and sale of electricity and provides enforcement power to the commission to address any market power abuses.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 35.004, 39.001, 39.151, and 39.157.

§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.

(4) The requirements of this subsection shall terminate on October 1, 2006.

(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, (relating to Wholesale Market Design for the Electric Reliability Council of Texas) 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 offer cap shall be terminated on the date that the system-wide offer caps are implemented as required in §25.505(g)(6) of this title.

(i) **Termination of MCSM**. ERCOT shall terminate its use of the Modified Competitive Solution Method, ordered by the commission in Docket No. 24770, on October 1, 2006.

§25.504. Wholesale Market Power in the Electric Reliability Council of Texas Power Region.

(a) **Application.** This section applies to all generation entities in the Electric Reliability Council of Texas (ERCOT). This section defines the term "market power," as that term is used in §25.503 of this title (relating to Oversight of Wholesale Market Participants).

(b) **Definitions.** The following terms, when used in this section, shall have the following meanings, unless the context or specific language of a section indicates otherwise:

(1) **Generation entity** – An entity that controls a generation resource. An entity affiliated with a generation entity shall be considered part of that generation entity.

(2) **Market power** – The ability to control prices or exclude competition in a relevant market.

(3) **Market power abuse** – Practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. Market power abuses include predatory pricing, withholding of production, precluding entry, and collusion.

(c) **Exemption based on installed generation capacity.** A single generation entity that controls less than 5% of the installed generation capacity in ERCOT, as the term "installed generation capacity" is defined in §25.5 of this title (relating to Definitions), excluding uncontrollable renewable resources, is deemed not to have ERCOT-wide market power. Controlling 5% or more of the installed generation capacity in ERCOT does not, of itself, mean that a generating entity has market power.

(d) **Withholding of production.** Prices offered by a generation entity with market power may be a factor in determining whether the entity has withheld production. A generation entity with market power that prices its services substantially above its marginal cost may be found to be withholding production; offering prices that are not substantially above marginal cost does not constitute withholding of production.

(e) **Voluntary mitigation plan.** Any generation entity may submit to the commission a mitigation plan for ensuring compliance with §25.503(g)(7) of this title or with the Public Utility Regulatory Act §39.157(a). Any plan that is submitted may be revised, with the agreement of the market participant, and approved or rejected by the commission. Adherence to a plan approved by the commission constitutes an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan. Failure to adhere to a plan approved by the commission does not, of itself constitute a violation of §25.503(g)(7) of this title, but may be treated in the same manner as any other violation of a commission order.

§25.505. Resource Adequacy in the Electric Reliability Council of Texas Power Region

(a) **General.** The purpose of this section is to prescribe mechanisms that the Electric Reliability Council of Texas (ERCOT) shall establish to provide for resource adequacy in the energy-only market design that applies to the ERCOT power region. The mechanisms are intended to encourage market participants to build and maintain a mix of resources that sustain adequate supply of electric service in the ERCOT power region, and to encourage market participants to take advantage of practices such as hedging, long-term contracting between market participants that supply power and market participants that serve load, and price responsiveness by end-use customers.

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

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

(2) **Load entity** – an entity that owns or controls a load resource, including, but not limited to, a load acting as a resource (LaaR) or a balancing up load (BUL), as those terms are defined in the ERCOT Protocols.

(3) **Resource entity** – an entity that is a generation entity or a load entity.

(c) **Statement of opportunities (SOO).** ERCOT shall publish a SOO that provides market participants with a projection of the capability of existing and planned electric generation resources, load resources, and transmission facilities to reliably meet ERCOT's projected needs. A SOO published in even-numbered years shall use a ten-year study horizon and be published by December 31 of those years. A SOO published in odd-numbered years shall use a five-year study horizon and be published on or around October 1 of those years. ERCOT shall prescribe reporting requirements for generation entities and transmission service providers (TSPs) to report to ERCOT their plans for adding new facilities, upgrading existing facilities, and mothballing or retiring existing facilities. ERCOT also shall prescribe reporting requirements for load entities to report to ERCOT their plans for adding new load resources or retiring existing load resources.

(d) **Projected assessment of system adequacy (PASA).** Beginning no later than October 1, 2006, unless otherwise specified below, ERCOT shall provide market participants with information to assess the adequacy of resources and transmission facilities to meet projected demand in the following two reports:

(1) Each month, ERCOT shall publish a Medium-Term PASA for each week of the subsequent three years beginning with the week after the Medium-Term PASA is published. At a minimum, each Medium-Term PASA shall include the following information:

(A) Load forecast by ERCOT zone or area;

(B) Ancillary service requirements;

(C) Transmission constraints; and

(D) Aggregated information on the availability of resources, by ERCOT zone or area, including load resources.

(2) Each day, ERCOT shall publish a Short-Term PASA for each hour for the seven days beginning with the day the Short-Term PASA is published.

(A) At a minimum, each Short-Term PASA shall include the following information:

(i) Load forecast by ERCOT zone or area;

(ii) Ancillary service requirements;

(iii) Transmission constraints; and

(iv) Aggregated information on the availability of resources, by ERCOT zone or area, including load resources.

(B) By October 1, 2006, ERCOT shall file at the commission a plan to incorporate the impact of transmission constraints into its Short-Term PASA at a later date.

(e) **Filing of resource and transmission information with ERCOT.** ERCOT shall prescribe reporting requirements for resource entities and TSPs for the preparation of PASAs. At a minimum, the following information shall be reported to ERCOT:

(1) TSPs shall provide ERCOT with information on planned and existing transmission outages.

(2) Generation entities shall provide ERCOT with information on planned and existing generation outages.

(3) Load entities shall provide ERCOT with information on planned and existing availability of LaaRs, specified by type of ancillary service, and BULs.

(4) Generation entities shall provide ERCOT with a complete list of generation resource availability and performance capabilities, including, but not limited to:

(A) the net dependable capability of generation resources;

(B) projected output of non-dispatchable resources such as wind turbines, run-of-the-river hydro, and solar power; and

(C) output limitations on generation resources that result from fuel or environmental restrictions.

(5) Load serving entities (LSEs) shall provide ERCOT with complete information on load response capabilities that are self-arranged or pursuant to bilateral agreements between LSEs and their customers.

(f) **Publication of resource and load information in ERCOT markets.** To increase the transparency of the ERCOT-administered markets, ERCOT shall post at a publicly accessible location on its website, beginning no later than October 1, 2006, the information required pursuant to this subsection.

(1) The following information in aggregated form, for each settlement interval and for each area where available, shall be posted two calendar days after the day for which the information is accumulated.

(A) Quantities and prices of offers for energy and each type of ancillary capacity service, in the form of supply curves.

(B) Self-arranged energy and ancillary capacity services, for each type of service.

(C) Actual resource output.

(D) Load and resource output for all entities that dynamically schedule their resources.

(E) During the operation of the market under a zonal market design, scheduled load and actual load. During the operation of the market under a nodal market design, firm scheduled load, scheduled load with "up to" limits on congestion charges, and actual load.

(2) During the operation of the market under a nodal market design, the following day-ahead market information in aggregate form shall be posted two calendar days after the day for which the information is accumulated: load bids, including virtual loads, in the form of day-ahead bid curves, and cleared load.

(3) The following information in entity-specific form, for each settlement interval, shall be posted as specified below.

(A) During the operation of the market under a zonal market design:

(i) Portfolio offer curves for balancing energy and for each type of ancillary service, for each area where available, shall be posted 30 days after the day for which the information is accumulated beginning October 1, 2006, except that, for the highest-priced offer selected or dispatched by ERCOT for each interval, ERCOT shall post the offer price and the name of the entity submitting the offer 48 hours after the day for which the information is accumulated. In the event of interzonal congestion, ERCOT shall post, separately for each zone, the offer price and the name of the entity submitting the highest-priced offer selected or dispatched.

(ii) Other offer-specific information for each type of service and for each area where available shall be posted 90 days after the day for which the information is accumulated beginning March 1, 2007. Effective March 1, 2008, this information shall be posted 60 days after the day the information was accumulated. The information subject to this disclosure requirement is as follows:

(I) final energy schedules for each QSE;

(II) final ancillary services schedules for each QSE;

(III) resource plans for each QSE representing a resource;

(IV) actual output from each resource; and

(V) all dispatch instructions from ERCOT for balancing energy and ancillary services.

(iii) The information posted shall include the names of the resources in the portfolio that were committed, the name of the entity submitting the information, the name of the entity controlling each resource in the portfolio.

(B) Two months after the start of operation of the market under a nodal market design:

(i) Offer curves (prices and quantities) for each type of ancillary service and for energy at each settlement point in the real time market, shall be posted 30 days after the day for which the information is accumulated except that, for the highest-priced offer selected or dispatched for each interval on an ERCOT-wide basis, ERCOT shall post the offer price and the name of the entity submitting the offer 48 hours after the day for which the information is accumulated.

(ii) Other resource-specific information, as well as self-arranged energy and ancillary capacity services, and actual resource output, for each type of service and for each resource at each settlement point shall be posted 30 days after the day for which the information is accumulated.

(iii) The posted information shall be linked to the name of the resource (or identified as a virtual offer), the name of the entity submitting the information, and the name of the entity controlling the resource. If there are multiple offers for the resource, ERCOT shall post the specified information for each offer for the resource, including the name of the entity submitting the offer and the name of the entity controlling the resource.

(C) The load and generation resource output for each zone, for each entity that dynamically schedules its resources, shall be posted 90 days after the day for which the information is accumulated beginning March 1, 2007. Effective March 1, 2008, the information required by this subparagraph shall be posted 60 days after the day for which the information is accumulated. Two months after the start of operation of the market under a nodal market design, the information required by this subparagraph shall be posted 30 days after the day for which the information is accumulated.

(D) ERCOT shall use §25.502(e) of this title (relating to Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas) as the basis for determining the control of a resource and shall include this information in its market operations data system.

(g) **Scarcity pricing mechanism (SPM).** ERCOT shall administer the SPM. The SPM shall take effect on January 1, 2007, unless the commission by order changes this date. The SPM shall operate as follows:

(1) The SPM shall operate on an annual resource adequacy cycle, starting on January 1 and ending on December 31 of each year.

(2) For each day of the annual resource adequacy cycle, the peaking operating cost (POC) shall be 10 times the daily Houston Ship Channel gas price index for the previous business day. The POC is calculated in dollars per megawatt-hour (MWh).

(3) For the purpose of this section, the real-time energy price (RTEP) shall be measured as the price at an ERCOT-calculated ERCOT-wide hub.

(4) In the annual resource adequacy cycle, the peaker net margin (PNM) shall be calculated as $\sum$((RTEP – POC) * (number of minutes in a settlement interval / 60 minutes per hour)) for each settlement interval when RTEP – POC >0.

(5) Each day ERCOT shall post at a publicly accessible location on its website the updated value of the PNM, in dollars per megawatt (MW).

(6) The system-wide offer caps shall be as follows:

(A) The low system offer cap (LCAP) shall be set on a daily basis at the higher of:

(i) \$500 per MWh and \$500 per MW per hour; or

(ii) 50 times the daily Houston Ship Channel gas price index of the previous business day, expressed in dollars per MWh and dollars per MW per hour.

(B) Beginning March 1, 2007, the high system-wide offer cap (HCAP) shall be \$1,500 per MWh and \$1,500 per MW per hour.

(C) Beginning March 1, 2008, the HCAP shall be \$2,250 per MWh and \$2,250 per MW per hour.

(D) Beginning two months after the opening of the nodal market, the HCAP shall be \$3,000 per MWh and \$3,000 per MW per hour.

(E) At the beginning of the annual resource adequacy cycle, the system-wide offer cap shall be set equal to the HCAP and, except for increases authorized in this section, maintained at this level as long as the PNM during an annual resource adequacy cycle is less than or equal to \$175,000 per MW. During an annual resource adequacy cycle, the system-wide offer cap shall be increased in accordance with the schedule authorized in this section unless the PNM has been exceeded by that date. If the PNM exceeds \$175,000 per MW during an annual resource adequacy schedule, the system-wide offer cap shall be reset at the LCAP for the remainder of that annual resource adequacy cycle.

(F) The Independent Market Monitor, as part of its responsibilities pursuant to Public Utility Regulatory Act §39.1515(h), may conduct an annual review of the effectiveness of the SPM.

(h) **Development and implementation.** ERCOT shall use a stakeholder process to develop protocols that comply with this section. Nothing in this section prevents the commission from taking actions necessary to protect the public interest, including actions that are otherwise inconsistent with the other provisions in this section.

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 amended with changes to the text as proposed, and §25.504, relating to Wholesale market Power in the Electric Reliability Council of Texas Power Region and §25.505, relating to Resource Adequacy in the Energy Reliability Council of Texas Power Region, are hereby adopted with changes to the text as proposed.

SIGNED AT AUSTIN, TEXAS the 23rd day of AUGUST 2006.

PUBLIC UTILITY COMMISSION OF TEXAS

PAUL HUDSON, CHAIRMAN

BARRY T. SMITHERMAN, COMMISSIONER

I respectfully dissent from the Commission's decision to require the rapid disclosure of disaggregated information contained in subsection (f)(3). In addition to the reasons I articulated during our open meeting discussions for my dissent, I am very concerned that such a rapid disclosure of disaggregated market information could force market participants to disclose proprietary information and trade secrets to their detriment. The independent market monitor is in place to prevent market manipulation, rendering this potentially harmful disclosure of information entirely unnecessary. Instead, disclosing both the disaggregated load and resource data in 90 days would both protect proprietary information and satisfy the sound public policy behind disclosure.

In all other respects, I join the adoption of this rule.

JULIE PARSLEY, COMMISSIONER