Control Number: 52631

Item Number: 47

PROJECT NO. 52631

REVIEW OF THE ERCOT SCARCITY PRICING MECHANISM	§	**PUBLIC UTILITY COMMISSION**
	§	
	§	**OF TEXAS**

PROPOSAL FOR ADOPTION FOR AMENDMENTS TO 16 TAC §25.505 AS APPROVED AT THE DECEMBER 2, 2021 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts amendments to 16 Texas Administrative Code (TAC) §25.505, relating to reporting requirements and the scarcity pricing mechanism in the Electric Reliability Council of Texas power region, with changes to the proposed rule as published in the October 22, 2021 issue of the *Texas Register* (46 TexReg 7130). These amendments modify the value of the high system-wide offer cap (HCAP) by lowering it from the current $9,000 per megawatt-hour (MWh) and $9,000 per megawatt (MW) per hour to $5,000 per MWh and $5,000 per MW per hour. In this adoption, citations to Public Utility Regulatory Act (PURA) §39.160 refer to that section of the Texas Utilities Code added by Senate Bill 3 § 18, 87th Regular Session.

The commission received comments on the proposed amendment from Austin Energy, Hunt Energy Network, LLC (HEN), the City of Houston (Houston), Intersect Power, East Texas Electric Cooperatives, Inc. (ETEC), Jupiter Power LLC (Jupiter Power), Lower Colorado River Authority (LCRA), NextEra Energy Resources (NextEra), the Office of Public Utility Counsel (OPUC), South Texas Electric Cooperative, Inc. (STEC), Steering Committee of Cities Served by Oncor (OCSC), the Texas Advanced Energy Business Alliance (TAEBA), Texas Competitive Power Advocates (TCPA), Texas Electric Cooperatives, Inc. (TEC), Texas Industrial Energy Consumers

(TIEC), Texas Public Power Association (TPPA), the Texas Solar Power Association (TSPA), Vistra Corp. (Vistra). No party requested a hearing.

Recommendations for the Value of HCAP

Currently, the value of the HCAP is set at $9,000 per MWh. The proposed amendment would lower this value to $4,500 per MWh.

HEN, OCSC, OPUC, NextEra, ETEC, and Houston generally supported reducing the value of the HCAP to $4,500 per MWh. NextEra stated that a $4,500 per MWh HCAP strikes an adequate balance between creating incentives for generation and load to perform and limiting the financial risk to those purchasing energy at the HCAP. ETEC stated that lowering the value of the HCAP ensures energy prices remain affordable during the upcoming winter season. Houston commented that reducing the HCAP to $4,500 per MWh would lessen the financial impact to customers during scarcity events.

TEC supported the commission's proposal to lower the HCAP, provided that the change is part of a broader initiative to move away from a crisis-based market model toward supply stability and an environment characterized by regulatory certainty. TEC also emphasized the importance of being mindful of how adjustments to the HCAP and the Value of Lost Load (VOLL) will interact with price-responsive demand. TPPA supported adjusting the HCAP downward to a value between $4,500 per MWh and $9,000 per MWh. Jupiter Power could support an HCAP value of $4,500 per MWh or $6,000 per MWh, depending on the outcome of the Brattle scenario analysis discussed at the October 21, 2021 Open Meeting and other wholesale market design changes made by the commission.

TIEC argued that the HCAP should be set at $6,000 per MWh. TIEC expressed concern that reducing the HCAP to $4,500 per MWh will dilute incentives for generator performance and demand response in the real-time market. TIEC explained that some of its members provide incremental demand response between $4,500 and $9,000 per MWh that will likely be lost if the HCAP is reduced to $4,500 per MWh. TAEBA echoed the concerns raised by TIEC, recommending that the commission exercise caution when adjusting the HCAP, as too large of a reduction could result in a decline in participation in economic demand response in the ERCOT power region.

TIEC also contended that the risk of high real-time prices encourages forward hedging by market participants to manage real-time price exposure. Reducing the financial penalty for a resource that fails on a forward obligation in real time, or for a load serving entity that is not properly hedged during emergency conditions, could have adverse impacts on the long-term reliability and health of the ERCOT market. TIEC further stated that the lower the HCAP is set, the more pressure there will be to increase generator revenues from other sources, such as changing the parameters of the Operating Reserve Demand Curve (ORDC) to have a "longer fatter tail." TIEC argued that such changes could shift additional revenues to intermittent resources and impose an unjustified energy tax for consumers during times of sufficient real-time reserves.

STEC recommended that the commission refrain from modifying the HCAP until after the "Brattle Group's study" is completed. STEC maintained that wholesale changes to the market are best done with a comprehensive, holistic approach with input from stakeholders. STEC stated that constantly modifying the offer caps and ORDC parameters will be detrimental to the market, as it introduces additional regulatory uncertainty. Additionally, STEC expressed concern that any reduction in the HCAP without a fuel cost recovery mechanism could exacerbate energy supply issues during scarcity events when natural gas prices are high. Under the right conditions, STEC continued, it may not be economically feasible for generators to offer capacity into the market as fuel costs would be unrecoverable. Rather than altering the HCAP in isolation, STEC recommended that the commission look to the customer protection rules to ensure consumers are protected from exposure to volatile electricity costs.

Intersect Power stated it is unwise to lower the HCAP to $4,500 per MWh. TSPA commented that it will be difficult to raise the offer cap after lowering it. TSPA stated that the offer cap must be high enough for generators to have financial risk for outages and to encourage economic demand response when conditions warrant.

Commission Response

The commission modifies the language of §25.505(g)(6)(B) to set the HCAP at $5,000 per MWh and $5,000 per MW per hour.

After the extreme weather events of February 2021, the price cap of $9,000 per MWh has proven to be a liability on market participants and customers of ERCOT. The commission

agrees with HEN, OCSC, OPUC, NextEra, ETEC, and Houston that lowering the HCAP would help ensure prices remain affordable during the upcoming winter season and lessen the financial risk to customers during scarcity events. The commission also agrees with TIEC and TAEBA that lowering the HCAP too much would reduce the incentives for economic demand response.

Setting the HCAP at $5,000 per MWh and $5,000 per MW per hour strikes the best balance of ensuring appropriate generation is brought to the market using market-based mechanisms and incentivizing demand response during scarcity events while limiting extraordinary financial liability for all market participants and customers during such events. Additional changes to the wholesale market design are being considered in Project Number 52373.

Coordination Between Modifying the Value of HCAP and ORDC Changes

Nearly every commenter recognized the importance of aligning any changes to the value of the HCAP with any other changes made by the commission to the ERCOT wholesale market design.

OCSC and OPUC acknowledged that adjusting the HCAP is only one component of the needed comprehensive and holistic review of the ERCOT wholesale market design. TPPA acknowledged that the commission is simultaneously working on changes to ORDC in Project Number 52373, and TPPA encouraged the commission to carefully consider how modifications to the HCAP may affect the ORDC going forward. TEC supported lowering the HCAP with the understanding that this change will be done in concert with other market modifications, including changes to parameters of the ORDC, new ancillary service products, and other changes that support reliable fuel supply and system resilience. TSPA encouraged the commission to consider any changes to the HCAP in concert with modifications to the ORDC, as these matters are inextricably intertwined.

TCPA and Vistra supported a lower HCAP but stated that the HCAP reduction needs to be implemented in conjunction with the commensurate ORDC reforms needed to maintain existing revenues and provide investment signals to existing and new generation resource owners. TCPA and Vistra stated that the ORDC reforms need to incentivize economic commitment of the desired level of real-time operating reserves so that ERCOT does not have to rely on out-of-market commitment of resources to achieve the desired operating reserves. TCPA stated that this includes, at a minimum, increasing the probability of reserves falling below the minimum contingency level within the ORDC. TCPA recommended that the commission adopt all required ORDC changes prior to the end of 2021 so that such changes can become effective simultaneously with the lowered HCAP value. Vistra recommended modifications that include increasing the minimum contingency level and shifting the ORDC standard deviation parameter. Additionally, Vistra emphasized the importance that any ORDC changes need to be examined in light of the historical levels of offline reserves, which Vistra stated have been at about 33% of the online reserve levels.

STEC argued that reducing the HCAP in isolation would further degrade resource adequacy and reliability. LCRA agreed with STEC, commenting that a reduction in the HCAP should only be implemented in concert with corresponding ORDC changes to ensure the HCAP change will not harm the existing wholesale market. TAEBA averred that reducing the HCAP without simultaneously considering changes to other key components of the wholesale energy market and evaluating the financial impact of all changes together poses significant regulatory risk. Intersect Power specifically mentioned increasing the minimum contingency level and encouraged the commission to make this adjustment regardless of a decision to reduce the HCAP. Austin Energy suggested that the commission pause this rulemaking to allow for adequate time to analyze the impacts from changes to the HCAP. Austin Energy recommended that changes to the value of the HCAP be incorporated into the broader wholesale market design changes in Project Number 52373, because the appropriate HCAP level will be determined by other decisions regarding the market design construct.

HEN contended that the commission should take a holistic approach to reviewing the HCAP, VOLL, ORDC, Ancillary Service demand curves, and the power balance penalty curve. In the view of HEN, the current ORDC does not send the appropriate price signals, because the parameters have not been adjusted to reflect the recent discussion to procure 6,500 MW of reserves from generation resources. A lower value for VOLL could exacerbate this problem. HEN recommends, in conjunction with a $4,500 per MWh HCAP, setting VOLL at $9,000 per MWh, the minimum contingency level at 3,000 MW, and increasing the ORDC standard deviation parameter. NextEra strongly argued that any reduction in the HCAP needs to be offset by changes to the ORDC parameters that will shift the ORDC to the right so that the revised curve causes scarcity pricing to occur at higher reserve margins. NextEra recommended the following ORDC parameters to avoid a reduction in generation revenues: HCAP at $4,500 per MWh, VOLL at $15,000 per MWh, minimum contingency level at 2,300 MW, and shifting the ORDC to cause scarcity pricing to occur at higher reserve margins. Jupiter Power posited that a downward change in the HCAP necessitates changes to the ORDC curve, including lifting the minimum contingency level from 2,000 MW.

Commission Response

The commission declines to delay modifying the value of the HCAP. The system-wide offer cap begins each calendar year set to the HCAP. Then, if the peaker net margin exceeds three times the cost of new entry of a generation plant, as it did during Winter Storm Uri, the system-wide offer cap drops from the HCAP to the low system-wide offer cap (LCAP), which is substantially lower and serves as an important customer protection against high prices. The system-wide offer cap is set to the LCAP for the remainder of 2021, but it will revert to the HCAP on January 1, 2022. It is the intent of the commission that the lowered HCAP take effect before this date to maintain a degree of protection against high prices. However, the commission will consider additional market design changes in a future rulemaking project, informed by the requested analysis by Brattle.

Decoupling VOLL from the System-Wide Offer Cap in Effect

Several parties recommended that the commission consider decoupling VOLL from the system-wide offer cap in effect, as is currently required by §25.505(g)(6)(E). While not taking a position in its comments, Austin Energy recommended that the commission make a determinative decision as to whether the VOLL in the ORDC should be coupled to the system-wide offer cap or otherwise decoupled. HEN supported severing the link in §25.505(g)(6)(E) and keeping VOLL at $9,000 per MWh when the HCAP is in effect. Vistra recommended that the commission consider striking the provision in §25.505(g)(6)(E) that equates the value of VOLL to the system-wide offer cap that is in effect. Vistra stated that doing so will give the commission needed flexibility to study other proposals affecting VOLL that are already being discussed in Project Number 52373. NextEra encouraged the commission to evaluate decoupling the HCAP from VOLL to ensure that price-suppressing impacts of a reduced HCAP do not cause dispatchable generation revenues to decrease. Intersect Power stated that as the Texas economy and Texas residents' quality of life is increasingly dependent on electric and digital infrastructure, VOLL should be increasing, not decreasing. If the commission chooses to reduce the HCAP, Intersect Power requested that it decouple the HCAP from VOLL and increase VOLL to $20,000 per MWh as recommended by the Independent Market Monitor.

Commission Response

For purposes of this rulemaking, the commission retains the language in §25.505(g)(6)(E) that sets VOLL equal to the system-wide offer cap in effect. The commission will review alternative values of VOLL in Project Number 52373 and may reconsider this issue in a future rulemaking.

Emergency Pricing Program

Austin Energy, HEN, TIEC, ETEC and Houston all referenced either the emergency pricing program in PURA §39.160 or the need for an additional circuit breaker during extended periods of high prices, as experienced during Winter Storm Uri. Austin Energy encouraged the commission to consider the design of the emergency pricing program, given the dependence of this new pricing mechanism on the value of the HCAP. HEN and TIEC both commented that the commission should implement the emergency pricing programs in accordance with PURA

§39.160 to protect the market from sustained scarcity prices over a long duration and limit the financial risk exposure of extended real-time price excursions during extreme weather events. ETEC argued that implementing the additional measures recently put in place by the legislature in PURA §39.160 will help prevent extreme pricing events, like the one experienced during Winter Storm Uri. Houston pointed out that the lack of an effective circuit breaker during Winter Storm Uri contributed to the impacts felt by customers in Texas as much as the absolute level of the HCAP. Houston recommended that the commission add in a circuit breaker that would cap prices at the LCAP when the HCAP price signal no longer provides any material benefit to real-time resource adequacy or reliability.

Commission Response

The commission makes no changes in response to these comments. The emergency pricing program is beyond the limited scope of this rulemaking. The commission will establish the emergency pricing program as required in PURA §39.160 in a future rulemaking.

Additional Comments

Jupiter Power commented that the commission should consider seasonal ORDC curves and seasonal values for the HCAP and VOLL. It also recommended that the commission evaluate any changes to the HCAP one year from now, with additional reviews on a periodic basis to ensure the wholesale energy market is signaling investment in resources ensuring resource adequacy.

Austin Energy recommended that the commission consider expanding the scope of the cost recovery provision in §25.505(g)(7), which allows a resource entity to be reimbursed for operating losses when the LCAP is in effect, to apply to periods when the HCAP is in effect.

Vistra recommended the approval of a mechanism, such as the Dispatchable Standby Reserve product they recommended in Project 52373, by which additional resources are retained and available to the market as insurance when needed. Vistra argued this new product is complementary to the ORDC improvements and encouraged the commission to work towards concurrent or near-concurrent approval of all of the associated market design elements.

Commission Response

The commission declines to make changes in response to these comments. These recommendations are beyond the scope of this rulemaking. However, the commission encourages commenters to participate in Project Number 52373, which is evaluating market design issues more broadly.

These amendments are adopted under §14.002 of the Public Utility Regulatory Act, (PURA), which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; PURA §39.101, which establishes that customers are entitled to safe, reliable, and reasonably priced electricity and gives the commission the authority to adopt and enforce rules to carry out these provisions; and PURA §39.151, which grants the commission oversight and review authority over independent organizations such as ERCOT, directs the commission to adopt and enforce rules relating to the reliability of the regional electrical network and accounting for the production and delivery of electricity among generators and all other market participants, and authorizes the commission to delegate to an independent organization such as ERCOT responsibilities for establishing or enforcing such rules.

Cross reference to statutes: PURA §14.002, §39.101, and §39.151.

§25.505. Reporting Requirements and the Scarcity Pricing Mechanism in the Electricity Reliability Council of Texas Power Region.

(a) **General**. The purpose of this section is to prescribe reporting requirements for the Electric Reliability Council of Texas (ERCOT) and market participants, and to establish a scarcity pricing mechanism for the ERCOT market.

(b) **Definitions**. The following terms, when used in this section, 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. A load resource is a load capable of providing ancillary service to the ERCOT system or energy in the form of demand response and is registered with ERCOT as a load resource.

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

(c) **Resource adequacy reports.** ERCOT must publish a resource adequacy report by December 31 of each year that projects, for at least the next five years, the capability of existing and planned electric generation resources and load resources to reliably meet the projected system demand in the ERCOT power region. ERCOT may publish other resource adequacy reports or forecasts as it deems appropriate. ERCOT must prescribe requirements for generation entities and transmission service providers (TSPs) to report their plans for adding new facilities, upgrading existing facilities, and mothballing or retiring existing facilities. ERCOT also must prescribe requirements for load entities to report their plans for adding new load resources or retiring existing load resources.

(d) **Daily assessment of system adequacy.** Each day, ERCOT must publish a report that includes the following information for each hour for the seven days beginning with the day the report is published:

(1) System-wide load forecast; and

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

(e) **Filing of resource and transmission information with ERCOT.** ERCOT must prescribe reporting requirements for resource entities and TSPs for the preparation of the assessment required by subsection (d) of this section. At a minimum, the following information must be reported to ERCOT:

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

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

(3) Load entities will provide ERCOT with information on planned and existing availability of load resources, specified by type of ancillary service.

(4) Generation entities will 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) will 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 must post the information required in this subsection at a publicly accessible location on its website. In no event will ERCOT disclose competitively sensitive consumption data. The information released must be made available to all market participants.

(1) ERCOT will post the following information in aggregated form, for each settlement interval and for each area where available, 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) Actual load; and

(F) Energy bid curves, cleared energy bids, and cleared load.

(2) ERCOT will post the following information in entity-specific form, for each settlement interval, 60 calendar days after the day for which the information is accumulated, except where inapplicable or otherwise prescribed. Resource-specific offer information must 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 must 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. ERCOT will use §25.502(d) of this title (relating to Pricing Safeguards in Markets Operated by the Electric Reliability Council of Texas) to determine the control of a resource and must include this information in its market operations data system.

(A) Offer curves (prices and quantities) for each type of ancillary service and for energy in the real time market, except that, for the highest-priced offer selected or dispatched for each interval on an ERCOT-wide basis, ERCOT will post the offer price and the name of the entity submitting the offer three calendar days after the day for which the information is accumulated.

(B) If the clearing prices for energy or any ancillary service exceeds a calculated value that is equal to 50 times a natural gas price index selected by ERCOT for each operating day, expressed in dollars per megawatt-hour (MWh) or dollars per megawatt per hour, during any interval, the portion of every market participant's price-quantity offer pairs for balancing energy service and each other ancillary service that is at or above a calculated value that is equal to 50 times a natural gas price index selected by ERCOT for each operating day, expressed in dollars per megawatt-hour (MWh) or dollars per megawatt per hour, for that service and that interval must be posted seven calendar days after the day for which the offer is submitted.

(C) 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;

(D) The load and generation resource output, for each entity that dynamically schedules its resources; and

(E) For each hour, transmission flows, voltages, transformer flows, voltages and tap positions (i.e., State Estimator data). Notwithstanding the provisions of this subparagraph and the provisions of subparagraphs (A) through (D) of this paragraph, ERCOT must release relevant State Estimator data earlier than 60 days after the day for which the information is accumulated if, in its sole discretion, it determines the release is necessary to provide a complete and timely explanation and analysis of unexpected market operations and results or system events, including but not limited to pricing anomalies, recurring transmission congestion, and system disturbances. ERCOT's release of data in this event must be limited to intervals associated with the unexpected market or system event as determined by ERCOT. The data released must be made available simultaneously to all market participants

(g) **Scarcity pricing mechanism (SPM).** ERCOT will administer the SPM. The SPM will operate as follows:

(1) The SPM will operate on a calendar year basis.

(2) For each day, the peaking operating cost (POC) will be 10 times the natural gas price index value determined by ERCOT. The POC is calculated in dollars per megawatt-hour (MWh).

(3) For the purpose of this section, the real-time energy price (RTEP) will be measured as an average system-wide price as determined by ERCOT.

(4) Beginning January 1 of each calendar year, the peaker net margin will be calculated as: $\sum((\text{RTEP} - \text{POC}) * (\text{number of minutes in a settlement interval} / 60 \text{ minutes per hour}))$ for each settlement interval when RTEP – POC >0.

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

(6) **System-wide offer caps.**

(A) The low system-wide offer cap (LCAP) will be set at $2,000 per MWh and $2,000 per MW per hour.

(B) The high system-wide offer cap (HCAP) will be $5,000 per MWh and $5,000 per MW per hour.

(C) The system-wide offer cap will be set equal to the HCAP at the beginning of each calendar year and maintained at this level until the peaker net margin during a calendar year exceeds a threshold of three times the cost of new entry of new generation plants.

(D) If the peaker net margin exceeds the threshold established in subparagraph (C) of this paragraph during a calendar year, the system-wide offer cap will be set to the LCAP for the remainder of that calendar year. In this event, ERCOT will continue to apply the operating reserve demand curve and the reliability deployment price adder for the remainder of that calendar year. Energy prices, exclusive of congestion prices, will not exceed the LCAP plus $1 for the remainder of that calendar year.

(E) The value of the lost load will be equal to the value of the system-wide offer cap in effect.

(7) **Reimbursement for operating losses when the LCAP is in Effect.** When the system-wide offer cap is set to the LCAP, ERCOT must reimburse resource entities for any actual marginal costs in excess of the larger of the LCAP or the real-time energy price for the resource. ERCOT must utilize existing settlement processes to the extent possible to verify the resource entity's costs for reimbursement.

(h) **Development and implementation.** ERCOT must use a stakeholder process to develop and implement rules 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 certifies that the adoption has been reviewed by legal counsel and found to be within the agency's legal authority to adopt. It is therefore ordered by the Public Utility Commission of Texas that §25.505, relating to reporting requirements and the scarcity pricing mechanism in the Electric Reliability Council of Texas power region, is hereby adopted with changes to the text as proposed.

Signed at Austin, Texas the 2nd day of December 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

PETER LAKE, CHAIRMAN

Will McAdams

WILL MCADAMS, COMMISSIONER

Lori Cobos

LORI COBOS, COMMISSIONER

JIMMY GLOTFELTY, COMMISSIONER

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