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| **REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN** | §<br>§<br>§ | **PUBLIC UTILITY COMMISSION<br><br>OF TEXAS** |

**TEXAS ENERGY ASSOCIATION FOR MARKETERS' RESPONSE TO THE PUBLIC UTILITY COMMISSION'S QUESTIONS FOR COMMENT**

The Texas Energy Association for Marketers ("TEAM") hereby files its Responses to the Public Utility Commission of Texas Questions for Comment filed on August 3, 2021.[1] TEAM looks forward to continuing to work with the Commission and market participants on these market design issues. The focus of these comments is from the perspective of impacts to customers and customer facing entities, particularly retail electric providers ("REPs").

Reliability is the threshold requirement for the delivery of electric service to Texans. TEAM believes that a healthy competitive market will find the optimal way to deliver reliable electric service to customers so long as the wholesale cost to supply that service is transparent with sufficient liquidity. What we provide is a service that is technology neutral. In these times of expansive technology advances, it is important that the regulatory framework also be technology neutral. In addition, fundamental market principals should allow load participation and that such participation should count toward any out of market procurements that would support reliability.

COMMENTS

**Question No. 1:**
***What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?***

[1] TEAM members participating in these comments are: AP Gas & Electric, Chariot Energy, Demand Control 2, Energy Harbor, Fulcrum Energy d/b/a Amigo Energy, Hudson Energy Services, Iberdrola Solutions, Just Energy, NRG Energy, Inc., Rhythm, Southern Federal Power, SPG Energy, and Tara Energy.

Regardless of what mechanism or combination of mechanisms are chosen for adjustments to the ORDC, it is important that there be sufficient time from the decision to the actual implementation of the change. This is important to allow the impact of the new costs to be priced into new customer contracts. An abrupt change will disrupt existing customer contracts and required price changes in the middle of the customer contract. At minimum, customers need time to anticipate any future change. Further, the market needs time in order to respond to the future changes so that there are products available in the market to allow all market participants to hedge the cost.

The phasing of timing is consistent with the objectives of increasing the reserve margin. The primary driver is to ensure that the market signals provide the necessary incentives for new dispatchable resources – which can mean many forms of generation, storage, and load resources. With the general exception of some load resources, it will take some time for new dispatchable resources to be ready to offer into the grid. The regulatory certainty of revenue stream can coincide with that timing. The regulatory certainty can be created now, and the regulatory changes be in place by the time the new resources would be ready to deliver their resources to the grid.

**Question No. 2:**
***Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?***

a. ***If so, how should that minimum commitment be determined?***
b. ***How should that commitment be enforced?***

TEAM continues to prefer market solutions with proper signals. However, to the extent the Commission supports ERCOT's recent efforts to mandate operating reserves that are inflated because of a concern related to renewable output variability and unanticipated unplanned forced outage of generation, there may need to be some changes. The creation of a new reliability service to firm up renewable output would help address the need for additional operating reserves.

**Question No. 3:**
***What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.***

In the past, Ancillary services have never been used as a substitute for reserve margin. The existence of a reserve margin ensures reliability in extreme circumstances. Ancillary services have historically been designed to cover unanticipated forecast error in the amount of load on the system and the short-term risk of the sudden loss of a generation unit. However recent changes to the quantity and eligibility to supply ancillary services have changed the capacity payments made for ancillary services to a defacto supplemental reserve margin. The impact on customers and those who serve them must be considered in this analysis.

If ERCOT is to procure capacity through ancillary services in this manner the cost should be socialized in a competitively neutral way that can be reasonably priced into customer contracts. Consideration should be given to assigning the cost either to the cost causer (i.e. generation that continually faces unplanned outages) or to all customers through a funding mechanism created and collected through transmission and distribution utilities ("TDUs"). For example, a transmission fee could be created to provides funds sufficient for ERCOT to conduct an auction for a forward strip of ancillary services that would be used for this purpose of creating reliability reserves.

In addition, it is critical to a healthy competitive market, that the ancillary services be structured in a way to allow load resources to participate in the supply of ancillary services. This is especially true where the ancillary services are being used as a substitute for reserve margin.

TEAM proposes a new mechanism for allocating reliability related costs, including costs related to ancillary services and capacity. All reliability actions—from ERCOT's procurement of additional ancillary services to the creation of any new, special ancillary services in response to

SB3—should be socialized across the market, rather than borne unequally and without sufficient advance notice by individual market participants through load ratio share.

Under the proposed reliability cost mechanism, the collection of reliability related costs would flow through the transmission utilities. The transmission utilities could collect the costs through Transmission Cost of Service ("TCOS") which would create a non-bypassable charge. The utilities could collect a fixed per MWh charge with period true ups based on, for example, annual periods. This alternative would have an added benefit of better avoiding customer confusion, as, from an end-use customer perspective, this would present a fixed, less-complex charge that REPs can more effectively communicate and include on their Electricity Facts Labels ("EFLs").

**Question No. 4**
***Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?***

Existing REP programs demonstrate strong customer interest and participation in residential demand response, but opportunities exist for enhanced residential load response. To expand the number of REPs that are able to offer demand response programs to residential customers, TEAM recommends that the Commission redirect a significant portion of the ERCOT TDU energy efficiency programs to REP-offered energy savings products and services, as well as REP participation in TDU residential load management programs. All customers in the competitive retail market have a REP; therefore, this action will ensure more residential customers are reached in a customer-conscious, market-efficient way.[2]

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[2] Unlike third party demand response providers, REPs are subject to the Commission's extensive customer protection rules, which help ensure that customers enrolled in REP-offered programs are provided sufficient information about the terms of their participation. Additionally, because REPs are responsible for procuring sufficient resources to meet their projected load, it is imperative that REPs have visibility into the potential for large scale

The ERCOT TDUs collectively expend over $100 million each year to satisfy their statutory obligation under PURA § 39.905 to achieve certain minimum energy savings goals.[3] Thus, dedicating a greater portion of the TDUs' annual energy efficiency spend to REP-offered energy savings products and services and REP participation in residential load management programs would ensure that more residential customers can be incentivized to reduce their electricity consumption when needed most to enhance reliability of the grid. Rather than increasing the TDUs' already sizable spending levels, the Commission could evaluate which lower performing existing TDU energy efficiency programs could have their funds rededicated to REP-offered residential products, services, and demand response programs to ensure end use customers do not pay higher rates. Because REPs are responsible for procuring sufficient resources to meet their projected load, it is imperative that REPs have visibility into planned reductions to their projected load (and subsequent increases in load when a demand response event ends), which visibility can be lacking when residential customers participate in TDU residential load management programs through entities other than their REP. Accordingly, in addition to increased spending, this is another opportunity for improvement to the TDU residential load management programs.

The current landscape of energy-efficiency programming needlessly complicates the roles of market participants, greatly relying on third parties who are not REPs to offer payments or concessions that resemble retail plans for smart-device performance. Such third parties may view the TDU, and not customers, as their client, if the funding for their business substantially or entirely

reductions to their projected load (and subsequent increases in load when the demand response event ends), which visibility can be lacking when residential customers participate in demand response programs offered by third parties.

[3] *See 2021 Energy Efficiency Plans and Reports under 16 TAC § 25.181*, Project No. 51672.

derives from regulated-rate energy-efficiency funding. Unlike REPs, they also may not have the obligation and incentive to manage a portfolio of loads, of which understanding customer demand is an essential component. REPs are subject to extensive customer protection rules, and must engage in the business of serving these customers as a whole (not as part of an *ad hoc* program). Accordingly, it is less likely that a REP-oriented residential DR program will leave customers "shocked to find their smart thermostats were raised remotely."[4]

With respect to smart thermostat programs that automatically reduce a customer's electricity usage in time of peak demand, the Commission should ensure all providers of such services are subject to and adhere to the Commission's customer protection rules. REPs are subject to those rules, which provide numerous safeguards to ensure customers receive the information they need to make an informed decision about the services they are enrolling in (e.g., specific contract terms, transparent billing). However, REPs are not the only entities that provide residential load control services. This can lead to customer confusion as was evidenced during a residential demand response testing event that occurred earlier this summer when the customers of a third party demand response provider contacted REPs with complaints about the event and questions about how to cancel their enrollment,[5] but the REP was unable to help because the customer was not enrolled in the REP's program.[6] This event was unfortunate because it may have left those customers with a negative impression of demand response programs when those

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[4] "'Woke up sweating': Some Texans shocked to find their smart thermostats were raised remotely," KHOU-11 (June 18, 2021). https://www.khou.com/article/news/local/texas/remote-thermostat-adjustment-texas-energy-shortage/285-5acf2bc5-54b7-4160-bffe-1f9a5ef4362a

[5] *Some Texas Power Companies are Remotely Raising Temperatures on Customers' Thermostats*, Newsweek (Jun. 21, 2021) (online edition).

[6] If a customer is enrolled in a thermostat control program with a demand response ("DR") provider, they would need to contact the DR provider to cancel their agreement because their REP would be unable to do so.

programs can actually be a positive way for customers to contribute to reducing demand on the electric grid when conservation is needed.

**Question No. 5:**
***How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?***

ERCOT's Emergency Response Service ("ERS") program could be modified to provide additional reliability benefits by evolving to be more accommodating to residential demand response. ERCOT is currently authorized to spend a maximum of $50 million per calendar year on ERS.[7] A portion of this spending and any additional increased spending in ERS should be dedicated to enabling residential demand response by REPs.

For the reasons discussed in response to Question No. 4, residential demand response participation in ERCOT's ERS program should be limited to programs offered by REPs or entities that are subject to and adhere to the full suite of the Commission's customer protection rules. Automatically reducing a customer's usage during a scarcity event, which often occurs during time periods of extreme heat or cold, is something that should be reserved for those market participants with a firm understanding of their customer service obligations and that are subject to the Commission's oversight.

**Question No. 6:**
***How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?***

Greater transparency of the insufficiency of current ability of ERCOT operators to manage for these factors may assist in the development of any solutions. Performance metrics related to

[7] 16 TAC § 25.507(b)(2).

the voltage swings associated with each of these elements would allow better quantification of the cost of these elements and allow development of the tools to address them.

## CONCLUSION

TEAM appreciates the opportunity to engage in these very important discussions. It is a critical element of this analysis to include impacts on customers and the ability to manage the cost impacts of any decisions that result from this process.

Respectfully submitted,

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## CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing document was served upon all parties on August 16, 2021.

Catherine J. Webking

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