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REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

HUNT ENERGY NETWORK, L.L.C.'S RESPONSE TO COMMISSION STAFF'S REQUEST FOR COMMENT ON MARKET DESIGN QUESTIONS

Hunt Energy Network, L.L.C. (HEN) submits this response to the Public Utility Commission of Texas ("PUCT" or "Commission") Staff's request for comment on questions concerning market design to assist Staff in preparing an agenda for the Commission's work sessions on Market Design. Commission Staff requested comments by August 16, 2021, and therefore, this response is timely filed.

HEN appreciates the opportunity to offer these comments and looks forward to working with the Commission, Commission Staff, and stakeholders to develop effective and practical solutions to address market design issues.

I. EXECUTIVE SUMMARY

The Texas electric market structure supports electric reliability in an economically effective way and facilitates competitive choices by energy customers and producers that contribute to grid reliability. Successful wholesale competition has attracted significant investment in renewable resources, energy storage, load management systems, and behind-the-meter (BTM) generation. These investments have brought technological innovations, including distributed energy resources (DERs), to the State. Given the rapid increase in technology options for BTM resources and DERs, the Commission and the Electric Reliability Council of Texas, Inc. (ERCOT) should ensure that interconnection and market rules do not unduly limit their integration. In a time of rapid growth in demand and increasing integration of intermittent resources and other technological advances, the Commission should continue to encourage competitive solutions to the electric grid by removing legal and market barriers and facilitating the efficient use of ancillary services and increasing capacity, thereby reducing overall risk. The Commission Staff's questions concerning market design identify key issues that should be explored to enhance the resiliency of the ERCOT grid and market. Below are highlights of a few of HEN's responses to Staff's questions.

1. <u>HEN recommends revisions to the ORDC.</u> The Operating Reserve Demand Curve (ORDC) is an effective tool to incent new generation, but the current ORDC does not accurately reflect the value of operating reserves; positive changes can be made to advance competitive solutions. In response to Staff's questions, HEN proposes the following

improvements, which ought to drive further investment in existing and new dispatchable generation (especially upon the implementation of real time co-optimization) and better value resources based on their ability to provide these services:

- ERCOT should change the minimum contingency level used to calculate the ORDC (i.e., the value of "X") from 2,000 MW to 3,000 MW to reflect the reliability value and need for at least 2,800 MW of Responsive Reserve Service (RRS) and 200 MW of Regulation-Up Service (RUS), as recently increased by ERCOT.
- ERCOT should increase the standard deviation used to determine ORDC (i.e., flatten the ORDC curve) so that the revised ORDC will reflect ERCOT's recently-augmented ancillary services plan (of up to 8,000 MW) intended to enhance grid reliability.

These changes to the ORDC will encourage participation in the real-time market by triggering smaller price adders more often, and ERCOT's augmented ancillary services plan will shift overall revenues toward ancillary services. This latter result is to be expected as zero variable-cost resources continue to depress energy market prices. Consequently, these changes to the ORDC should be considered in conjunction with changes to implement the emergency pricing required by SB 3.

2. <u>HEN recommends additional responsive reserve ancillary service products.</u> Fast responding reserve services are critical to maintaining grid reliability, especially as additional intermittent resources are integrated into the system and traditional thermal generators that provide inertial support represent a smaller percentage of available resources. Accordingly, HEN recommends the following additional ancillary services:

i. Use RRS for frequency responsive service only (as opposed to providing energy as well), in the same way Regulation Service (Reg-Up and Reg-Down) is not released to Security Strained Economic Dispatch (SCED) today.

ii. ERCOT should implement a subset of RRS for fast frequency response services separate from slower-responding load resources, while also considering various frequency triggers to stagger deployment of those services to address overshoot (overcorrection) issues that may occur when using rapid responsive reserves. These changes would allow greater participation by resources with fast frequency response capability, regardless of the technology used to provide the services. A similar technology-neutral result could be achieved by also making ONSC (ON Synchronous Condenser) status technology neutral to allow ESRs to offer RRS using ONSC status.

3. <u>HEN recommends adjustments to ERCOT's ancillary services plan to recognize the value of responsive reserves</u>.

- ERCOT should continue to procure at least 2,800 MW of RRS at all times. Continuation of this recent increase by ERCOT will ensure enough Physical Responsive Capability (PRC) to arrest frequency in situations where there is a sudden loss of a substantial amount of generation (i.e., the two largest units in ERCOT).

- As part of its ancillary services plan, ERCOT could plan to procure about 1,400 MW of RRS, which is a 10-minute service, in addition to the 2,800 MW recommended above (until ERCOT Contingency Reserve Service (ECRS) is implemented, which will result in a similar quantity of additional 10-minute reserves).

4. HEN recommends that the Commission and ERCOT facilitate market-based aggregation of customer loads and DERs. Aggregation of small generation, controllable load, and BTM assets can enable grid balance and stability close to the customer. Realization of these benefits will require development of regulatory and operational changes to allow these resources to provide ancillary service reliability products to the electric grid.

II. INTRODUCTION AND GENERAL COMMENTS

For more than twenty-five years, the Legislature, PUCT, ERCOT, and countless stakeholders have guided one of the most successful competitive electric markets in the nation. While the Legislature has expressed a preference for competitive, rather than regulatory, methods to manage the market, practical and limited regulation is often necessary to help ensure critical reliability for extremely rare events and to appropriately protect customers. Winter Storm Uri exposed situations where market design parameters and regulatory policies were not in place to protect both the electric grid and customers during such an extreme event. The market is fundamentally sound, but there are opportunities for improvement.

The Legislature and PUCT have started addressing certain gaps in regulatory policy—such as weatherization requirements, critical load designation, natural gas and electricity coordination during extraordinary events, and the protection of residential and small commercial customers from abnormally large market variations in price. Likewise, the issues explored by Commission Staff's questions on market design are critical to enhancing the resiliency of the ERCOT grid and market.

HEN is a Dallas-based developer and operator of distributed energy resources. HEN currently has 100 megawatts (MW) of energy storage resources (ESRs) in advanced stages of development throughout Texas targeting operation by first quarter 2022, with an additional 400 MW to be deployed over the following 36 months. These resources are expected to play a valuable role in efficiently managing resources interconnected with the ERCOT electric grid. Distributed ESRs provide several benefits to the grid and market, including (1) improving grid reliability, (2) providing ancillary services to the market, (3) paving the way for the two-way distribution system of the future, and (4) deferring transmission and distribution infrastructure upgrades over time. HEN looks forward to meaningfully contributing to creating a more robust grid—to the benefit of all Texans—and appreciates the opportunity to work with the Commission, Commission Staff, and stakeholders to identify, evaluate, and address potential weaknesses in the ERCOT grid and market.

III. RESPONSE TO MARKET DESIGN QUESTIONS

Question 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?

HEN Response: Changes to the ORDC may be an appropriate way to drive investment in existing and new dispatchable generation as the ORDC, at present, does not accurately reflect the value of operating reserves. Currently, the ORDC is based on the Value of Lost Load (VOLL) and the Loss of Load Probability (LOLP), where the LOLP assumes one additional MW of load shed would be avoided if one additional MW of ancillary services, such as Responsive Reserve Service (RRS), Regulation-Up Service (RUS), or Non-Spinning Reserve Service (NSRS), were procured. This approach to determining the ORDC is appropriate when the necessary ancillary services are acquired from operating reserves (i.e., excess generating capacity) and are able to provide energy to the grid through ERCOT's economic dispatch model, or Security Constrained Economic Dispatch (SCED). However, when there is no excess generating capacity—as the extreme conditions during Winter Storm Uri demonstrated—reserves, including responsive reserves, were dispatched as energy, leaving insufficient frequency response capability. Had another major unit dropped off the ERCOT grid during the early hours of February 15, 2021, the depletion of these reserves could have led to a complete grid failure, due to the system's inability to address frequency decay. In this situation, failure to procure one additional MW of RRS, for example, could have resulted in the loss of potentially thousands of MW of load (due to the grid failure) rather than only one MW as the ORDC assumes. ERCOT's recent decision to procure 6,500 MW of reserves from generation resources (a significant increase above the prior approximately 4,500 MW amount) implies there is reliability value in procuring up to about 8,000 MW of reserves (including approximately 1,500 MW of ancillary services from load resources). The current ORDC, on the other hand, reflects almost no value for reserves in excess of about 6,000 MW. There is a logical disconnect between the ORDC and ERCOT's assessment of the value of reserves underlying ERCOT's recently-augmented ancillary services plan.

To address this disconnect, HEN recommends the following changes to the ORDC.

These changes ought to drive further investment in existing and new dispatchable generation (especially upon the implementation of real time co-optimization) and would better align the ORDC with the value of reserves:

i. ERCOT should change the minimum contingency level used to calculate the ORDC (i.e., the value of "X") from 2,000 MW to 3,000 MW to reflect the reliability value and need for at least 2,800 MW of RRS and 200 MW of RUS, as recently increased by ERCOT. ERCOT should also increase the standard deviation used to determine ORDC (i.e., flatten the ORDC curve) so that the revised ORDC will reflect ERCOT's updated ancillary services plan (of up to 8,000 MW) intended to enhance grid reliability.

   These types of changes to the ORDC would send a strong price signal for investment in dispatchable resources in a sustained and dependable manner by triggering smaller price adders more frequently, rather than the volatile price signals under the current ORDC, which occur only in times of extreme scarcity. These changes also would permit a reduction of the system-wide offer cap (SWCAP), should the Commission decide that lowering the SWCAP is an appropriate tradeoff to accompany ERCOT's recent changes to its ancillary services plan, and should be considered in conjunction with changes to implement the emergency pricing required by SB 3.

ii. The second sentence of Question 1 asks commenters to consider applying the ORDC only to generators who "commit" in the DAM. HEN believes such a policy could unnecessarily increase costs. Commitment typically implies a physical commitment requirement to keep a resource online or to start up a resource, with the expectation that the resource will be paid for its start-up and minimum load costs. When there is sufficient generating capacity to reliably meet load and reserve requirements, however, there is no need to require generation resources to commit in the DAM and doing so could result in an inefficient and unnecessary increase in costs because more generation is likely to be brought online than is needed. If, instead of "physical commitments," the question is asking whether resources should be required to submit "offers" in the DAM for energy or ancillary services, i.e., make financial commitments, in order to be eligible for the ORDC adders, then HEN believes that type of requirement could be workable but, in any event, nothing should discourage participation in the real-time market.

iii. Considering there have been three significant outages in ERCOT since the onset of wholesale competition, and all have occurred in January and February, it is clear that what works in the summer is inadequate in the winter. HEN has not studied this issue in depth, but, as the ORDC is the major tool being used by the Commission and ERCOT to enhance market investment signals, it would be a natural knob to turn to drive winter-focused price signal enhancements.

Question 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?

HEN Response: No, ERCOT should not require all generation resources to offer a minimum commitment in the DAM year-around as a precondition for participating in the energy market. As described in HEN's response to Question 1 above, when there is more than enough generating capacity available to reliably meet load and reserve requirements, it would be inefficient and would unnecessarily increase societal cost to require the commitment of additional resources. Requiring a physical commitment of a resource in the DAM when there is no expectation that those additional resources will be needed to reliably meet load and reserve requirements would unnecessarily increase costs because more generation is likely to be brought online than is needed.

However, in situations where generation capacity is tight, ERCOT could require generation resources to submit an offer for energy and/or ancillary services for all hours in the DAM. A potential consequence of a resource failing to submit the required offer could be that the resource is precluded from receiving the ORDC adder in either the AS Imbalance Payments or the Real-Time Settlement Point Prices (RTSPPs). This approach likely would result in sufficiently high financial penalties to market participants so that requiring a minimum physical commitment in the DAM would be unnecessary. For efficiency and reliability reasons, HEN believes it is important not to impose any physical commitment requirement on resources in the DAM or excess commitment in real-time unless doing so is essential for reliability. For this same reason, if the Commission adopts a DAM offer requirement as a condition to receive ORDC adders, a resource should not be excluded from participation in the real-time market as such a penalty could adversely impact reliability. DAM energy awards are financial in nature and imposing a physical requirement to commit resources to generate energy would be inefficient and adversely impact reliability, particularly for resources with emission, fuel, storage, or startup limitations.

Question 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.

HEN Response: HEN agrees that new or revised ancillary service products and reliability services and procedures should be developed to ensure reliability under a variety of extreme conditions. During Winter Storm Uri, the release of RRS capacity as economically-dispatched energy relatively early in the storm left the grid's important frequency response capacity depleted. Physical Responsive Capability (PRC) was at a very low level just before the precarious drop in frequency at 1:45 am on February 15, 2021. When energy offers were below the prices at resource nodes, RRS capacity was dispatched up by SCED and the capacity from other resources was dispatched down by SCED. The capacity that was dispatched down did not contribute to PRC as effectively as capacity providing RRS would have (i.e., it did not have the same ability to arrest frequency decay). A better solution than releasing RRS capacity to SCED would have been for the system to have (a) deployed offline non-spinning reserves, (b) directed RUC of additional capacity, or (c) reduced load. Reserving RRS capacity to respond to frequency deviations is the most reliable way of ensuring adequate PRC and reliability of the system. Due to resources either delaying updates to their high sustainability limits or telemetering incorrect PRC values, or both, the grid was actually only a few hundred MW—instead of the 900 MW or more ERCOT believed was available—or about five minutes, away from triggering Under Frequency Load Shed (UFLS) at 59.3 Hz, which potentially would have led to a catastrophic grid collapse. Repeat of this dire situation must be avoided. ERCOT must maintain sufficient ancillary services to arrest frequency and protect against blackouts. Reserving RRS capacity until it is the last available resource is the most reliable way of ensuring adequate PRC and reliability of the system.

Historically, inertia from conventional generators (i.e., energy stored in large rotating generators) in ERCOT facilitated planning and operation of the grid. This stored energy is valuable when a large generator goes offline, as it can temporarily make up for the lost power (and resists a frequency drop), at least long enough to allow ERCOT to identify the lost generation and respond. As the grid has evolved with increasing integration of inverter-based resources (e.g., wind, solar, and ESRs), which do not provide the same type of physical inertia that traditional rotating generators do, ERCOT must adjust to ensure system reliability. ERCOT studies have shown that just 450 MW of fast frequency response (FFR) can lower the critical inertia level from 100 gigawatt-seconds (GW•s) to 90 GW•s. By better using the FFR capabilities of resources like ESRs, which can respond many times faster than the traditional mechanical response (batteries can respond in 250 milliseconds), and revising the process by which RRS is procured and deployed, the Commission and ERCOT can mitigate the risk of a grid collapse caused by extreme weather events, like Winter Storm Uri. The practice of deploying (releasing RRS and/or FFR for possible dispatch by SCED) should be discontinued and frequency responsive services should be reserved to respond to frequency events. In addition, in re-designing ancillary services, barriers should be removed so resources that can best provide a needed service or attribute are allowed to compete, and the dispatch and price of ancillary services should be consistent with the value of the service they provide to the system.

Based on the above, consider the following changes to ancillary service products and procedures to address situations when operating reserves drop below a certain level or system frequency cannot be maintained above certain levels and durations ("Emergency Action Alert (EAA) Procedures"):

i. Use RRS for frequency responsive service only (as opposed to providing energy as well), in the same way Regulation Service (Reg-Up and Reg-Down) is not released to SCED today. This change would prevent the release of RRS capacity to SCED as energy and keep it available until it is most needed (to address rapid frequency decay). These resources should be prioritized for frequency response and should not be deployed for scarcity.

ii. ERCOT should implement a subset of RRS for fast frequency response services separate from slower-responding load resources, while also considering various frequency triggers to stagger deployment of the services to address overshoot (overcorrection) issues that may occur when using rapid responsive reserves. Frequency overshoot concerns can also be addressed by developing new RRS-down and FFR-down products. These changes would allow greater participation by resources with fast frequency response capability, regardless of the technology used to provide the services. A similar technology-neutral result could be achieved by also making ONSC (ON Synchronous Condenser) status technology neutral to allow ESRs to offer RRS using ONSC status.

iii. ERCOT should continue to procure at least 2,800 MW of RRS at all times, some of which would be the procured in the separate FFR service class. Continuation of this recent increase by ERCOT will help ensure enough PRC to arrest frequency in situations where there is a sudden loss of a substantial amount of generation (i.e., loss of the two largest generating units at the same time). This reserve margin is justified in light of the potentially unfathomable cost of not being able to arrest frequency decay and the corresponding loss of the grid. Regulation Service (Reg-Up and Reg-Down) and RRS are essential reliability products and should be used accordingly. As part of its ancillary services plan, ERCOT could plan to procure about 1,400 MW of RRS, which is a 10-minute service, in addition to the 2,800 MW described above (until ERCOT Contingency Reserve Service (ECRS) is implemented, which will result in a similar quantity of additional 10-minute reserves) to allow for the replenishment of deployed RRS and restore frequency. RRS is already considered a short-duration product with a 10-minute response time (similar to ECRS) This additional RRS procurement will likely reduce ERCOT's current non-spinning reserve procurement by a similar amount.

iv. Modify EEA Procedures and criteria to ensure there is sufficient PRC to arrest frequency deviations associated with the sudden outage of the largest unit on the system at nearly all times. A simple revision to the applicable protocols would be to increase the minimum PRC threshold that triggers when ERCOT directs TSPs and DSPs to shed load under EEA Level 3 to an amount based on the largest unit on the system. There should not be a risk of the grid collapsing due solely to the outage of a single generating unit, and the load shed trigger should be consistent with that assumption. The following change to ERCOT Protocol 6.5.9.4.2(3) could be made to provide additional reliability protection:

> "When PRC falls below ~~1,000~~ 1,400 MW and is not projected to be recovered above ~~1,000~~ 1,400 MW within 30 minutes, or when the clock-minute average frequency falls below 59.91 Hz for 25 consecutive minutes,

ERCOT shall direct all TSPs and DSPs or their agents to shed firm Load, in 100 MW blocks, distributed as documented in the Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover ~~1,000~~ 1,400 MW of PRC within 30 minutes."

v. Develop regulatory and operational changes to allow BTM resources to provide ancillary service reliability products to the electric grid. Power customers have become power producers because of technological advancements and the decreasing costs of energy assets, like solar panels and battery cells. There are large amounts of BTM generators and ESRs being developed that can contribute to grid reliability. Aggregation of small generation, controllable load, and BTM assets can enable grid balance and stability at the edge of the system. But realization of these benefits will require changes to Commission rules and ERCOT Protocols.

Question 4: Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?

HEN Response: While REPs have the ability to offer time-of-use and energy management products for residential customers, residential load response remains a critical and unrepresented resource in the market. End-use customers have historically been viewed primarily as passive participants in the market—only engaged through time-of-use rates and when in response to a call for conservation from the grid operator or their retail provider. As technology has evolved and costs have decreased, more resources have been deployed at the residential level, most often behind-the-meter. The capability to aggregate existing and incent additional customers to install and deploy these incremental resources can buttress overall economic growth and reliability by efficiently increasing market capacity, while small asset owners will have more opportunities to participate in the market and remain hedged against extreme volatility. The existing market rules and protocols do not permit nor encourage residential participation, leaving these resources inaccessible to ERCOT. HEN recommends the Commission and ERCOT investigate regulatory policy and market solutions to provide greater opportunities to integrate customer aggregation and automated demand response programs into management of the grid.

Question 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?

HEN Response: HEN believes that emergency load response programs, like emergency response service (ERS), have a significant role to play today and in the future. As stated in HEN's response to Question 4, HEN believes there are opportunities to expand load response programs by allowing more loads—including residential customers and aggregated BTM loads and resources—to participate in demand response at all times, including outside of energy emergencies. Using additional eligible load resources as a source to both decrease capacity needs and respond to frequency deviations has advantages over conventional frequency response services because they have fast response times. HEN has not studied this issue in depth, but looks forward to developing market rules and systems that would allow these changes.

Question 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?

HEN Response: The changes recommended as part of HEN's response to Question 3 should improve the ability to manage inertia and frequency, especially by making RRS a frequency response service only and by providing a subclass of RRS for fast frequency response, separate from slower-responding load resources. In addition, the Commission and ERCOT may want to consider both a new inertia ancillary service and a localized reactive power product, and HEN looks forward to working with stakeholders to develop these services.

IV. CONCLUSION

HEN appreciates the Commission' s consideration of these comments and looks forward to participating in further discussions with the Commission, Commission Staff, and stakeholders to develop effective and practical solutions to enhance system reliability by developing appropriate regulatory policy and adjusting the ERCOT market design.

Respectfully submitted,

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