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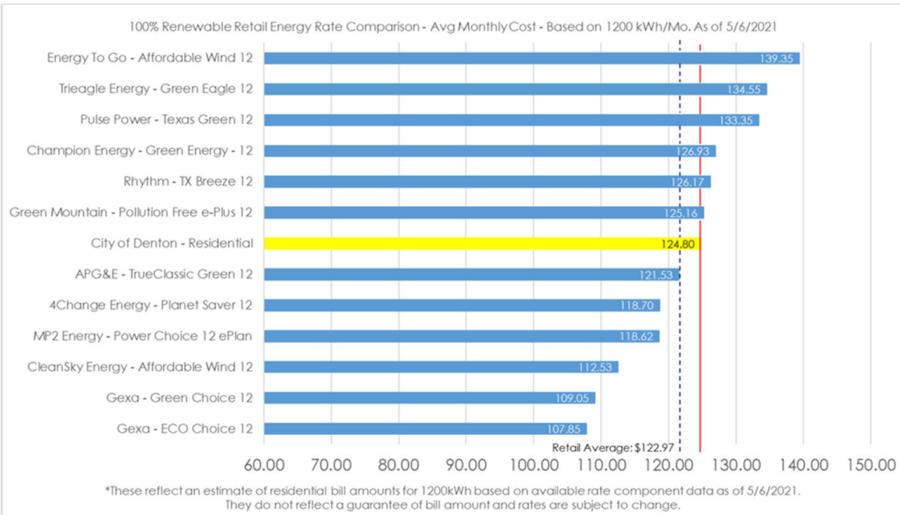
REVIEW OF WHOLESALE MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

CITY OF DENTON dba DENTON MUNICIPAL ELECTRIC'S RESPONSE TO STAFF'S QUESTIONS FOR COMMENT

The City of Denton through its Municipally Owned Utility (MOU) Denton Municipal Electric (DME) appreciates the opportunity to respond to the questions for comment proposed by the Public Utility Commission of Texas (Commission) in advance of its upcoming work session on market design. Formed in 1905, DME provides electric service to over 60,000 meters in Denton, TX and is a Non-Opt In Entity (NOIE) under Section 16.3 of the ERCOT protocols. DME operates four (4) Qualified Scheduling Entities (QSE). The City of Denton adopted the Denton Renewable Resource Plan (DRRP) in February 2018 which targeted 100% renewable energy supply for the City under contract by the 2021[1]. For 2021, DME will achieve 100% renewable energy supply using energy generated by a portfolio of intermittent wind and solar generation facilities under long-term Power Purchase Agreements (PPA) and energy generated by DME's Denton Energy Center (DEC), a 225 MW natural gas peaking plant consisting of 12 reciprocating engines and associated generators. Key to the success of DME's rate stability is the Denton Energy Center, to back-up the inevitable periods when the portfolio of renewables is not able to operate. DME provides this overview, along with supporting information to demonstrate that, as a vertically integrated utility, operating wholly within the ECOT market, it is commercially and technically feasible to assemble a power supply portfolio that relies upon the environmental and economic benefits of interruptible renewable resources while maintaining competitive rates. Further, were the entire market to use this approach for power supply in what will be a larger and larger intermittent dominated market, generation reliability can be achieved. In a way, the Denton model provides ERCOT with a road map to firming up the intermittent resources that are inevitably going to be built. Figure 1 depicts the relative residential rates of DME as compared to competitive offerings for 100% renewable energy supply.

[1] Resolution No. 18-085. A Resolution of the City of Denton adopting the "Renewable Resource Plan" to meet the future need of its electric customers with 100% renewable energy and rescinding resolution No. R 2016-014 (The Denton Renewable Plan).

Figure 1 – 100% Renewable Energy Retail Electric Rates in ERCOT



Texas electric consumers should continue to realize the environmental and low cost benefits of these intermittent resources. Wwe believe that the PUCT has the responsibility to continue to accommodate these low cost renewable resources, to maintain the value proposition that they bring the ERCOT market and to target policy and regulations to increase the amount of quick starting natural gas generation needed to provide a level of generation adequacy during the times when these intermittent resources are not operating.

Wind additions in ERCOT are expected to increase by as much as 20.5% from July 2021 through December 2022[2] with total installed wind capacity at 39,067 MW. Solar additions are anticipated to increase from 8,674 MW in July 2021 to as high as 22,437 MW in December 2022[3]. The PUCT must direct ERCOT to take immediate, targeted action to provide economic incentives to; a) increase the reliability of the existing dispatchable fleet; b) create an economic incentive to install quick starting, low capital cost natural gas fired generation that will "back-up" intermittent resources and c) create incentives to investment in energy storage, both short term (1-4 hours) and long-term (>4 hour). To be clear, Denton supports the continued development of renewable energy

[2] See Capacity Changes by Fuel Type Charts July, 2021 monthly http://www.ercot.com/content/wcm/lists/219848/Capacity_Changes_by_Fuel_Type_Charts_July_2021_monthly.xls

[3] http://www.ercot.com/content/wcm/lists/219848/Capacity_Changes_by_Fuel_Type_Charts_July_2021_monthly.xls

resources and items (a) and (b) above are a transitory step as energy storage, powered by renewables and other non-carbon emitting resources continue to achieve economic and operating efficiencies.

Weatherization of generation resources along with natural gas infrastructure address much of the causation of the winter storm Uri catastrophe. However, the PUCT's lack of authority over the natural gas delivery system in ERCOT and the history of capital intensive investment programs to firm up natural gas infrastructure lead Denton to believe and recommend that the PUCT do what is necessary to mandate actions within its control for the benefit of all Texans. Maintaining the cost competitive advantage of our energy mix along with the environmental benefits associated with renewables should be at the top of the list as the PUCT considers market redesign. The citizens of Denton and the rest of Texas expect a solution that increases grid reliability while maintaining these economic and environmental benefits.

I. Answers to Staff Questions

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?**

Changes to the ORDC necessary to increase investment in dispatchable generation must result in more predicable and more consistent gross margins[4] that are sufficient to drive highly dependable and reasonable rates of return on invested capital in dispatchable resources. Specific problems with the ORDC paradigm, in light of changing generation resource mixes include:

a. To the extent that the ORDC paradigm is maintained, significant changes will be needed. First, the $9,000 VOLL cap must be lowered. As was demonstrated during winter storm Uri, prolonged market clearing prices at $9,000/MWh did nothing to increase generation availability but only caused catastrophic financial consequences to market participants. While $9,000/MWh provides a potential economic windfall to

[4] Goss Margin is the difference between the energy revenues achieved by the generator and the variable cost of generation including fuel and variable O&M.

generators if they can run, given that the financially traded products used in ERCOT to hedge risk are settled based upon the real-time market price, failure to perform during prolonged periods of $9,000/MWh are likely to result in defaults and bankruptcies of the independent power producers if such assets have prudently hedged their market price risk[5]. Second, the ORDC reliability price adders must be present more hours of the year without significant risk of $2000 -$9000/MWh prolonged price excursions which could be accomplished by increasing the multiplier[6] used in the ORDC calculations.

b. Keeping VOLL at $9,000/MWh and clearing prices at that level puts dispatchable generating resources in a position where forced outages will almost certainly result in economic catastrophe since the current outage insurance market limits will be exceeded very quickly[7]. The result of such an event is the likely bankruptcy of the dispatchable generation resources and further erosion of grid stability.

c. REPs that do not prudently hedge their sales, face the same fate as generators for unhedged volumes. MOU's and Cooperatives, which still represent a sizable portion of the total ERCOT load, face these same risks if the VOLL is maintained.

d. ORDC assumes a normally distributed price path and sets standard deviations and amplitude to derive the ORDC curve and resulting scarcity prices. Lowering the VOLL will require increasing the multiplier and increasing the standard deviation to achieve sufficient scarcity premiums to support continued investment in existing dispatchable generation and new peaking units, controllable load resources and energy storage. The extent to which these parameters must be varied requires careful study and an understanding from all market segments that everyone must pay more to achieve the level of reliability our customers expect and deserve. Increasing RUC orders and adding ancillary service reserves to avoid generation scarcity episodes and potential

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[5] Hedging forward revenues from generation resources generally is accomplished through the sale of fixed price futures contracts that settle based upon a published index. These "swaps", whether physical or financial, when settled on the real-time ERCOT price exposes the hedger to extreme risk if the real-time price stays at or close the VOLL because the hedger will owe their trading counterparty the difference between the real-time price and the fixed price hedge.

[6] Wakeland, Richard, *Does the Increase in Wind Generation in ERCOT Justify An Arbitrary Increase to its ORDC LOLP Calculation.*

[7] For DME, summer outage insurance limits are between $20 and $25 million max payout. At 225 MW, and $9,000/MWh that limit is exceeded in 12.3 hours.

loss of load only go to depress energy prices in our energy only market, exacerbating what many have referred to as the “missing money” problem.

e. Intermittent resources, in our opinion, should not be excluded from participation in ORDC, should the Commission decide to keep this market construct. If they can contribute energy during times of scarcity, they should receive the scarcity premiums. If they are causing the scarcity, they will be offline or in a reduced generation output positions and will thus by the nature of ORDC, not receive any scarcity premiums.

Without a reward for committing generation in the day-ahead market, all generators are increasing their risk profile and will avoid such commitment unless mandated by regulation. The simple fact is that whether a generator is a wind resource or a coal resource, if the wind unexpectedly dies or there is a malfunction at a gas or coal unit during the period of the day-ahead commitment, the generator would be forced to cover at the then spot market price which will almost always be at a higher price because of the loss of supply. Other RTOs manage this risk by rewarding the generator who must commit into the day-ahead market a fixed revenue stream that could be forfeited if they do not participate in the day-ahead market. No such mechanism exists in the ERCOT energy only market.

With respect to the PUCT’s question regarding seasonality of ORDE dispatchability, we are not sure what is being asked. If the market is experiencing a generation shortfall, in the energy only market design, price signals should be sent to incentivize generators to run regardless of the time of year.

Applying ORDC to only units that commit in the day-ahead market under the ERCOT energy only market design does not merit further investigation in DME’s opinion. There are several major market design and operational problems that make such a process impractical. First, unless such day-ahead commitment is binding at the HSL for each unit participating, offerors will likely withhold capacity to hedge against potential forced outages that could have catastrophic economic consequences. Second, as a market that is, and will be even further dominated by intermittent renewables, whose day-ahead commitment would likely be low balled to protect them from covering shortfalls in what could be a much higher priced real-time market. For solar resources, predicting cloud cover is anything but an exact science. For wind generators, being able to accurately predict the timing of weather fronts, while improving, is anything but an exact science. Third, and perhaps most importantly, as potential offerors into a day-ahead market, generators will need to hedge their financial risk using traded products that settle based on the same temporal period (day-ahead). In ERCOT, the standard traded products settle against the real-time price not the day-ahead price. This is a bit of a chicken and egg dilemma for ERCOT market participants that represents significant risk that must be priced into any day-ahead offers.

The bottom line on the day-ahead ORDC concept from DME's perspective is that without mandates and OTC/Clearing markets that settle against a day-ahead index, such changes will simply increase the cost of energy to all Texas electric consumers without any reliability benefit.

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

The quick answer is No. Without significant penalties for failing to offer the HSL into the day-ahead market, and an associated economic reward, such a process will likely result in even more marginal dispatchable generation leaving the market. While the PUCT has stated recently that the Texas Legislature did not authorize the implementation of a capacity market, this question leads to that direction as PJM, NYISO, NEPool, and others, through their stakeholder processes, and through FERC rulings, have fully vetted the arguments for and against such a market design. None of those markets have however, faced the level of intermittent generation that ERCOT faces. As previously stated, if ERCOT had a deep and liquid day-ahead market that financial traders were willing to make markets in, generators and load would have an avenue to prudently manage their risk.

Imposition of such a requirement to the intermittent renewable resources is problematic since output is a function of wind speed or solar irradiation. While the science of forecasting wind speed and duration have improved, being able to accurately predict the output each hour or 15 minute interval for wind and solar resources will necessarily result in conservative offers on a day-ahead basis and because of the relative size of these renewable assets in the market makeup, hedging the day-ahead volumes will result in higher clearing prices in the day-ahead market because, if ERCOT awards day-ahead generation orders to dispatchable generation at offer prices higher than that offered by intermittent resources, costs will increase to the consumer. Any day-ahead mandatory offer market also creates risk management problems for hedgers as there is really no deep and liquid day-ahead settled traded products. The absence of these products are a direct result of the energy only market construct. These products trade and, in most cases, as the primary risk management instrument, in other RTO markets.

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?**

A larger concern to the entire market is the continued development of low-cost intermittent renewable generation and its impact on the variability of the number of hours that price adders will be assessed using the ORDC methodology. Additional solar should translate into less scarcity hours during daylight hours and while that is encouraging for the market, it throws additional doubt and variability into energy revenues that dispatchable generators can use to cover fixed costs. As previously discussed in the introduction section, increases of wind and solar over the next 18 months alone are anticipated to exacerbate the intermittency impacts on grid generation reliability. While geographical wind diversification and increases in solar generation and its non-correlation with wind speed have the potential to mitigate somewhat the risk of a large portion of the intermittent generation in the ERCOT market not performing at the same time, a weather episode as was seen during February 2021 in which there was very little wind and significant cloud cover across all of Texas, must be planed for. Without intervention by the PUCT to provide clear line of sight to a cash flow sufficient to cover the fixed costs[8], investment into dispatchable generation will not happen and the inevitable repeat of that catastrophe is a certainty. As an alternative to extensive changes the ORDC methodology, DME believes the development of a new ancillary

[8] Fixed Costs include: Principal, interest expense, fixed operating and maintenance costs, capital maintenance and associated financing/debt costs and a reasonable return on equity.

service charge for “Grid Reliability Service” or “GRS” is warranted. Such a charge would be uplifted as a non-by-passable charge to all ERCOT market participants[9]. Revenues collected from this new GRS would be collected by ERCOT would be used to fund annual GRS pools that would be directed to ERCOT Resources that provide generation reliability to back up the intermittent resources. DME recommends that these funds be used primarily for the following types of investment to increase generation reliability.

- Dual fuel capital investment at existing dispatchable generating resources. This category is recommended because; a) an economic incentive must be put in place to encourage less reliance on natural gas sources during times of “human need” and because the PUCT does not have the legislative authority to ensure that the natural gas production and transmission facilities needed to ensure reliable natural gas deliveries at all times despite the Texas Legislature’s intent to have these natural gas production facilities weatherized[10], and b) existing facilities that increase the probability that they will be able to generate during a natural gas pipeline disruption (as was seen during Uri) will decrease the amount of new generation that will be needed in the ERCOT grid.
- Quick starting natural gas generating resources that provide the needed intermittent back-up capacity at the lowest possible capital cost. ERCOT, using its stakeholder process, should establish dispatchable capacity criteria for a limited number of future years that will be a function of the number of wind, solar and energy storage resources that are highly likely to be interconnected and operating in such future years as well as retirements of generating resources and additions of controllable load resources. ERCOT would need to direct the analysis of the probability of widespread intermittent outages during peak demand periods as it relates to how much back-up dispatchable capacity is needed for each future year included. Using a third-party engineering firm to establish the annual fixed cost associated with incremental peaking capacity (similar to the PJM MOPR process), the annual GRS ancillary service adder can be calculated.

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[9] All ERCOT “Resources” including intermittent renewable resources would be assessed the generation reliability adder for all energy injected into the ERCOT market as would be all energy purchased from the market by LSEs. Intermittent resources would not be eligible for payments from GRS funds. Applicability to existing intermittent resources will be need to be studied in light of change in law provisions of renewable PPAs.

[10] See Section 4 of Senate Bill 3, Changes to Subchapter C, Chapter 86 of the Natural Resources Code.

DME does not lightly offer this ancillary market approach but we are concerned that immediate and meaningful action that demonstrates a commitment to clear sources of dependable cash flows to incentivize new investment is required. While a market-based bid and offer clearing mechanism for this new GRS is possible, we believe the market needs immediate certainty and our suggested approach will provide that. We also believe that under a GRS market construct, market changes focused on intermittent resources would be minimal and would not trigger Change in Law provisions[11].

ERCOT faces additional reliability risks that are not apparent now but will be exacerbated by additional renewable energy penetration. Soon, periods of low inertia will be most prevalent during shoulder months when thermal generation maintenance outages occur, and renewable generation is highest. To state it as simply as possible, low system inertia conditions reduces the time systems have to arrest a drop in frequency following a large generator trip or disturbance event, thus reducing reliability. There may be times in which the Day Ahead Market clearing prices may not be firm enough to commit enough thermal generation to provide the inertia needed on the grid due to high renewable energy production. During these periods of low inertia, ERCOT may be forced to deploy offline non-spin generation or procure additional thermal generation out of merit (RUC), all of which will have a negative impact to market price formation. It is for these reasons, and the fact that physics does not care about the economics, DME believes the development of a new ancillary service charge for “Inertia Reliability Service” or “IRS” may be warranted.

4. **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?**

ERS is an example of a service that has over time reduced the necessary market price signals needed to build new dispatchable generation in ERCOT. If the commission wishes to keep ERS going forward, we recommend changing the payment structure to incentivize longer duration. In

[11] Any market changes impacting renewables would likely trigger change-in-law provisions of PPAs resulting in higher costs to DME customers or termination of long-term power purchase agreements.

addition, if this is truly an emergency service, then weatherization should also be part of the qualification process.

5. Conclusion

The City of Denton and DME appreciates the opportunity to submit these comments on Staff's questions. We look forward to working with the Commission, its staff, and the stakeholders on these important questions and this broader discussion in the coming months.

Given that the Commission has multiple work sessions scheduled on market design in the coming weeks, and many market participants have indicated that the uncertainty of energy cash flows is a significant impediment to investment in additional dispatchable generation, we believe that the Commission should consider including representatives of the merchant generation financing community on a panel. This would avail the Commissioners of the opportunity to get the lending community's perspective on market changes that have the potential to facilitate investment in dispatchable generation.

Dated: August 15, 2021

Respectfully,

DocuSigned by:
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