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RULEMAKING TO ADDRESS THE USE OF NON-TRADITIONAL TECHNOLOGIES IN ELECTRIC DELIVERY SERVICE	§ § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ADVANCED ENERGY MANAGEMENT ALLIANCE'S INITIAL COMMENTS ON PROPOSED RULE

The Texas Chapter of the Advanced Energy Management Alliance ("AEMA")[1] submits these initial comments in response to questions published by the Public Utility Commission of Texas ("Commission") in this project. AEMA is a trade association under Section 501(c)(6) of the Federal tax code whose members include national demand response ("DR") and advanced energy management service and technology providers, as well as some of the nation's largest demand response resources, who support advanced energy management solutions due to the electricity cost savings those solutions provide to their businesses. This filing represents the opinions of AEMA rather than those of individual association members.

SUMMARY

This proceeding arose out of a request by a distribution utility for authorization to install energy storage devices on its distribution system as what it represented to be a cheaper alternative to upgrading transmission or distribution facilities to serve customer load.[2] The Commission dismissed the request and opened this project to examine the use

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1 For additional information about AEMA, please refer to website: http://aem-alliance.org.

2 *Application of AEP Texas North for Regulatory Approvals Related to the Installation of Utility-Scale Battery Facilities,* Docket No. 46368, Order (Feb. 15, 2018).

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of storage and other non-wires alternatives to meet transmission or distribution needs. Many of the questions that the Commission has sought comment on deal with energy storage and with the regulatory obstacles to utilities' ownership of storage. There are, however, other technologies and services that can be deployed to meet or defer a transmission or distribution need, including energy efficiency, demand response, and distributed generation. There is an alternative to utility ownership for meeting a transmission or distribution need: by incentivizing investments in these alternate technologies in specific locations where the need exists or by contracting with third parties for services that can meet or defer the transmission or distribution need.

AEMA Texas believes that the Commission should establish two regulatory principles in this proceeding and adopt a rule based on these principles:

1. Transmission and distribution utilities ("TDUs") should evaluate whether a transmission or distribution need can be met by non-wires technologies and services, including energy storage, demand response, energy efficiency, and distributed generation.
2. If a transmission or distribution need could potentially be met by a non-wires technology or service at a cost less than traditional technologies, the TDU should seek to facilitate the deployment of non-wires solutions by incentivizing investment by customers and third parties in the area where these solutions could meet or defer the need, or conduct competitive solicitations for the provision of service from non-wires technologies and services.

Below, AEMA Texas provides answers to the questions posed by the Commission.

1. **Apart from energy storage, what non-traditional technologies could provide a potential cost-effective solution to reliability issues on a utility's transmission or distribution system?**

There are several services, in addition to electricity storage, that potentially could be cost-effective alternatives to wires solutions to address a transmission or distribution need. These services include demand response ("DR"), distributed generation ("DG"), and energy efficiency, and specific technologies may include electric vehicles ("EVs"), water heaters, solar etc. The Commission should adopt an approach that relies first on cost-effective investments in alternative resources by third parties to meet a transmission need, where such an approach is a feasible solution. There are several advantages to such an approach:

(1) Incentivizing customers and third parties to make investments in these technologies avoids utility investments in resources that are at odds with the principles underlying the Texas competitive market.

(2) Because customers stand to benefit from these investments in managing their own electricity needs and providing them other benefits (comfort, convenience, etc.), the cost to provide the needed service to the transmission or generation grid is likely to be lower. Customers are already interested in putting these technologies in their homes and businesses for other uses.

(3) An approach that focuses on the system need, rather than a specific solution to meet it, should foster creative solutions (or combinations of solutions) to meet the system need.

2. **Can a transmission and distribution utility (TDU) legally own a non-traditional technology device, including energy storage equipment and facilities, to support reliability on its system, without a specific exemption in the Public Utility Regulatory Act? If so, under what legal authority could a TDU own such a device?**

We believe that a TDU's investment in resources that are widely used by customers, in which customers are showing great interest to help manage their energy needs, and in which generators are investing to participate in the competitive energy market would be at odds with the principles underlying the Texas competitive market. One of these key principles is the separation of competitive and regulated activities. Where services such as DR and technologies such as storage have shown or have the potential for widespread use by customers in managing their energy needs, they should be regarded as competitive energy applications, which utilities should not normally invest in.

In the AEP Texas North case cited above, the Commission did not resolve this issue, but dismissed the application to install storage devices on other grounds. However, utility ownership of storage or other non-wires technology should be avoided because alternatives exist for meeting such a need in a market-based approach, either by incentivizing customers to invest in resources that would address the transmission or distribution need or by procuring services from customers or third parties to address the need. Customers and third parties could own equipment that would meet or defer a transmission or distribution need, and such an arrangement should be the preferred option.

For example, today, customers own 1) equipment to allow them to provide DR and 2) systems to communicate with DR providers operating as qualified scheduling entities ("QSEs"). This permits them to communicate with ERCOT in connection with the provision of DR to ERCOT and to distribution utilities in connection with the provision of

DR under a utility's load management program. The same kinds of systems could permit DR to be provided as a non-wires resource to meet transmission or distribution needs without raising legal issues. Indeed, distribution utilities already can use their load management programs for their own system needs today.[3] Utilities using a DR resource would own only the kinds of equipment they own today to assess transmission and distribution system conditions and communicate the instructions for a DR provider to deploy or recall its contracted DR resources. Customer or third-party installation of energy storage, DG and third-party management of focused energy efficiency programs also could meet or defer a transmission or distribution need on a cost-effective basis. As is the case with DR, these options would not raise the issue of utility ownership of storage or the challenge of how it would operate in the wholesale market.

3. **How should any energy necessary for TDU implementation of a non-traditional technology device be measured and accounted for within the ERCOT market, without using Unaccounted for Energy (UFE)?**

Employing customer or third-party non-wires technologies does not raise the same metering and billing issues as utility ownership of storage. The problem arises for the utility because it is precluded from selling electric energy,[4] and thus AEP North sought permission to treat the energy used in charging or released in discharging the proposed batteries as Unaccounted-for Energy ("UFE"). Using a resource owned by a customer or third party as a non-wires alternative would avoid the need for measuring and accounting for energy and would not result in UFE.

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3 *See, e.g.,* Rulemaking Proceeding to Amend Energy Efficiency Rules, Project No. 39674, Comments of EnerNOC, Inc. on Proposed Rule at 2-6 (May 29, 2912).

4 Public Utility Regulatory Act, § 39.105.

For example, a customer providing DR is already metered, and its consumption is metered and charged to the customer. DR operates through a reduction in a customer's energy consumption when the load reduction is called for by ERCOT or a utility. A DR provider's change in energy consumption is metered at the customer premises where the DR resource is located, and the extent of the load reduction is calculated under routines developed by ERCOT or the utility. Any energy used in communications and operating the equipment to deploy the DR resource is also metered to the customer.[5]

Similarly, a customer or third party can operate a DG facility or storage facility and sell the output without the regulatory issues that the TDU faces. Finally, distribution utilities are required to conduct energy-efficiency programs, and they potentially could focus some of their programs on areas where there is a transmission and distribution need without raising issues related to the sale or metering of electricity.

Energy storage that is operating behind a customer's meter can look like load when it is charging and a reduction in load when the energy storage unit is discharging. DR can be active or passive. Active means that the DR resource, which may include storage, is bidding into the energy and/or ancillary services markets. Passive means the change in consumption is reflected in the meter reading and affects the customer's retail electricity bill, but even passive changes in load can affect wholesale market prices. Third-party energy storage also can be deployed in-front-of-the-meter ("IFOM"), at a sub-station, for example. In that instance, where the resource is providing grid support that is not directly associated with a customer load, the resource would charge or discharge at the wholesale rate. Discharges, or energy released onto the grid, could be bid into the energy market

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[5] Reductions in consumption for a DR resource is measured against a baseline, which represents what a customer would have consumed if not for the DR event.

consistent with the operation of the energy storage resource. If energy were released at the request of the TDU for reliability purposes, it is possible ERCOT could treat this as it does other ERCOT-ordered reliability actions.

4. In which situations and scenarios would it be appropriate for a TDU to deploy a non-traditional technology device for the purpose of supporting reliability on its transmission or distribution system?

A TDU that identifies a transmission or distribution need that potentially could be served by a non-wires alternative should be required to evaluate which customer or third-party energy alternatives or combination of energy alternatives would be effective in addressing the transmission or distribution issue and would do so cost-effectively. Once the utility identifies the need on the transmission or distribution system, including the location and the attributes of the area, it could issue a request for offers ("RFO") to the market that specifies the operating parameters of the resource. The utility can choose from among those offers the resource that best matches the grid need at the best price. To facilitate contracting with third-party service providers, it would be helpful to have a model contract drafted that fairly balances the risks and benefits of the service between the utility and the third-party service provider. In addition, there should be a standardized interconnection process, not only to expedite interconnection, but to reduce the amount of time and expense associated with interconnections if each instance is treated as a one-off negotiation.

5. **Should a Certificate of Convenience and Necessity (CCN) or other commission pre-approval process be required before the construction or procurement of utility-owned devices that use non-traditional technologies to support reliability on the transmission or distribution system? If so, what criteria would be appropriate for pre-approval of such devices and why? Should such a pre-approval process only apply for a limited time?**

There is a competitive DR sector operating in ERCOT today and wide adoption of DG. In addition, storage technology is being deployed in the region, so there should be no need for a utility to acquire non-wires alternatives directly. Rather, customers or third parties providing a DR, DG, or storage resource would own or acquire the needed equipment. In addition, because this is a competitive energy service, the utility should be precluded from providing DR or DG with its equipment.

6. **Should the commission's rules permit or require a TDU to contract with a non-utility service provider for the provision of a non-traditional technology device to support reliability on the TDU's transmission or distribution system? If so, what parameters should the commission stipulate for this arrangement?**

Yes. In many situations, there is a potential for non-wires alternative to meet transmission and distribution needs at a lower cost than installing additional transmission or distribution facilities, thereby saving money for customers. As discussed above, in situations in which a transmission or distribution need potentially could be met or deferred by a non-wires alternative, the Commission should require a TDU to consider: (1) providing incentives for non-wires alternatives to address the need, or (2) conducting an open solicitation process to identify resources that could meet or defer a transmission or distribution need. If the solicitation results in offers that will address the need, the utility should contract with a provider of a non-wire resource if the non-wires alternative is the most economical option for meeting or deferring the need that the TDU has identified.

7. If the commission were to adopt a policy of permitting a TDU to procure a non- traditional technology device for the purposes of supporting reliability on the TDU's transmission or distribution system, what potential effects would such a policy have on ERCOT wholesale market outcomes, and especially price formation, in the ERCOT market? What potential effects might such a policy have on the competitive retail market, if any?

If a TDU procures a non-wires resource from a customer or other third party in the manner suggested in the responses to prior questions, one important impact of such a policy would be the potential to obtain needed enhancements in transmission and distribution service at a lower cost to customers. To the extent that DR, DG, storage, or energy efficiency is deployed to maintain the reliability of the transmission or distribution system, there is a potential for the reduced load level to affect prices in the wholesale energy market. ERCOT stakeholders have developed a mechanism to address the potential for deployments of Emergency Response Service ("ERS") to affect market prices, and such a mechanism could be used to address DR that is used to meet transmission or distribution needs if the Commission is concerned about the impact of load reductions on price formation. In addition to compensation received from the TDU for providing a reliability services, resources that deploy energy, such as storage and DR, should be eligible for compensation as they are today, either by participating in the ERCOT energy market or off-setting their consumptions of energy from the market.

8. What market-based alternatives exist, if any, to address reliability issues on a TDU's transmission or distribution system?

Utility demand-management programs and DR participation in ERCOT ERS and the Responsive Reserve market are market-based uses of a non-traditional resource to maintain reliability. Responsive Reserves are procured by ERCOT in a competitive auction process on a next-day basis to meet contingencies that may arise on the electric system. Similarly, the demand-management programs and ERS procure DR (and, for ERS, distributed generation) through a competitive auction process on a seasonal basis to provide DR resources to maintain reliability. The existing ERS, Responsive Reserve and utility demand-management programs, however, focus on the transmission network, for the most part. Distribution utilities could, however, recruit the kinds of resources participating in these reliability programs to provide reliability enhancement on the distribution system.

Providing incentives to customers for alternative resources (such as energy efficiency or DG) primarily would be a market-based mechanism, because the incentives would be expected to cover a small part of the total investment that the customer would make in an alternative resource. Investment decisions would be made on the basis of the customer's expectations with respect to future benefits it would derive by reducing its future purchases of energy in the retail market and also with respect to other benefits that technology might provide. Similarly, a solicitation process to meet transmission or distribution needs would be a competitive mechanism for procuring resources to meet the transmission or distribution need. The difference between the existing DR programs and the use of non-traditional resources as a non-wires alternative to meet a transmission or distribution need is that the utility's need would be expected to be a long-term need, and any contract with a non-traditional resource provider probably would need to be longer than the current seasonal obligations in the demand management programs and ERS.

While Loads in SCED is an option, it currently has limitations such as the requirement for the DR resource to be associated with a Retail Electric Provider ("REP"). ERCOT does not recognize demand bidding as a separate resource from the provision of electricity supply, unlike other independent system operators that are subject to the Federal

Energy Regulatory Commission's jurisdiction. Further, there are requirements for customers to have telemetry which is usually cost prohibitive. Making ERCOT more DER friendly would be important for the success of DER participation.

9. How could a vertically integrated investor-owned utility maximize the value of an energy storage device without adversely affecting wholesale market outcomes and price formation in its respective market?

No comment.

10. What impediments exist to using non-traditional technology devices on utility transmission or distribution system?

The principal impediment to employing non-wires alternatives owned by a customer or third party today is that there is not any existing utility process by which such resources could be identified, procured, valued and deployed to meet transmission and distribution needs. In addition, streamlined contracting and easier access to ERCOT markets would facilitate the participation of DERs. The Commission could fill this gap by adopting a rule requiring the consideration of non-wires alternatives owned by customers or third parties.

11. Could the commission specify conditions under which a TDU could employ non- traditional technologies to support reliability? If so, what conditions would be appropriate?

We expect that, in many situations in which a TDU has identified a transmission or distribution need, there is a potential for the need to be met by a non-wires alternative at a cost lower than the use of traditional technologies. Many transmission and distribution needs arise in locations that currently are being served by the transmission and distribution system, but changes in load or the aging of equipment results in the need for new facilities. However, there also are situations in which an area is not currently served, and the utility needs to install distribution facilities or both distribution and transmission to serve the load, such that additional delivery facilities are essential. There may be other factors that would need to be considered in identifying the situations in which non-wires alternatives should be considered, and we expect that the discussions in this rulemaking proceeding will be valuable in identifying them.

12. If you are a utility, please provide a detailed overview of any batteries or other energy storage technologies on your transmission and distribution system in the state of Texas that are either currently operational or planned to be operational. Please explain the purpose, use, metering, and deployment of these technologies.

No comment.

13. Are there any other issues that the commission should consider addressing in this project?

One issue that should be addressed to facilitate the cost-effective use of energy-efficiency is modifying the avoided-cost calculation for situations in which a distribution utility is implementing an energy-efficiency program to address transmission or distribution needs. The current energy-efficiency rule provides that avoided cost is based on estimated generation costs.[6] Where an energy-efficiency program is specifically addressing a transmission or distribution need, the appropriate avoided cost calculation should include both avoided production and transmission or distribution costs.

Conclusion

There are competitive energy technologies and services that can be deployed to meet or defer a transmission or distribution need, including energy efficiency, demand response, and distributed generation. There also is an alternative to utility ownership for meeting a transmission or distribution need: incentivizing investments in these technologies in specific locations where the need exists or by contracting with third parties for services that

[6] PUC Substantive Rule 25.181(c)(2)(A).

can meet or defer a transmission or distribution need. AEMA Texas believes that the Commission should establish regulatory principles that support the use of non-traditional resources owned by customers and third parties as a means of meeting transmission and distribution needs, and adopt a rule based on these principles:

1. TDUs should be required to evaluate whether a transmission or distribution need can be met by non-wires alternatives.
2. If so, the TDU should seek to facilitate the deployment of non-wires alternatives by incentivizing investment by customers and third parties that could meet or defer the need or conduct a competitive solicitation for service from non-wires alternatives.

AEMA Texas appreciates the opportunity to submit comments in this project.

Respectfully submitted,

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