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PROJECT NO. 51603

REVIEW OF DISTRIBUTED ENERGY RESOURCES	§ § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

<u>EL PASO ELECTRIC COMPANY'S RESPONSES TO QUESTIONS FROM COMMISSION STAFF</u>

El Paso Electric Company (EPE) provides the following responses to questions from Commission Staff in its memorandum dated on April 29, 2022, in Project No. 51603.

I. <u>Responses</u>

1) ***Distribution planning and control:*** *What planning and control processes and practices should the Commission consider for greater DER participation and grid resilience? Which entities should be involved in planning and control processes and practices?*

Response:

Planning and control practices can vary by utility based on whether that utility is a member of a regional transmission organization (RTO) or independent system operator (ISO) and, for those that are members of an RTO or ISO, the requirements of the RTO or ISO to which a utility belongs. The Commission should also consider that every utility's primary goal is to cost-effectively maintain the reliability of the system. Consequently, incorporation of DER into any system should not hinder the ability of the utility to achieve that goal nor should it unduly shift costs to all ratepayers if the benefit to the system is minimal or non-existent. A DER should be expected to conform to a utility's current, prudent practices and utilize existing communication networks. With that in mind, the Commission should also weigh not only cybersecurity concerns as new, third-party technologies communicate with the network but also physical, critical infrastructure concerns as it relates to broadly sharing network information. As such, the current regulatory model in which the Commission reviews and approves programs offered by a utility is a sound means of assessing (1) new technologies and their related programs to ensure the safety and reliability of the system and (2) appropriate cost allocations to ensure affordable rates for all customers.

i) *What are the different utilization and participation formats for existing DERs on distribution networks?*

Response:

At present, the distributed generation resources on El Paso Electric Company's (EPE or the Company) distribution network are predominantly solar resources located behind the customer meters. There are also a small amount of behind-the-meter battery storage installations. Currently, those distributed generation resources are not aggregated via any platform for utility control. EPE does, however, currently offer customers with smart thermostats the ability to engage in a demand response program whereby EPE has the ability to adjust those participating customers' thermostats in order to lower demand on the system.

EPE is analyzing DER programs in light of the recent interest by customers in electric vehicles (EV). For one, EPE is developing a managed charging pilot program. This program will gauge the acceptance and efficacy of managed charging of residential and commercial customer EVs. Without such a program, EV owners will either immediately charge their car upon getting home, which usually coincides with a system's standard peak, or later in the evening, which results in a significant increase in demand between the hours of 6:00 PM and 10:00 PM. Managed charging effectuates a win-win for the customer and the system as the software controlling the program will (1) ensure that the customer will have their vehicle charged to their desired level by the time they need it and (2) minimize EV load impact on the grid.

Another EV related DER program EPE is exploring is vehicle-to-grid ("V2G") charging[1]. This program would allow EPE to access a customer's batteries in order to increase energy on the system during peak or a scarcity event. Along this same line, EPE is also exploring the system benefits of offering customer-sited batteries to customers with large electric vehicle fleets. A customer-sited battery will give customers with large-fleets or heavy-duty fleets the ability to more actively control charging to minimize costs without overburdening EPE's system. Additionally, this should reduce the cost of fleet conversion

[1] The technology is still in its infancy, but companies like Blue Bird have indicated a production of all-electric school buses with V2G capability as a standard: Electric School Buses (blue-bird.com)

as it may reduce the need for system upgrades to the distribution system.[2] And, much like a standard V2G program, EPE will have the ability to access the battery, which may reduce the need for additional peaking resources.

Finally, EPE is also exploring working with customers in the development and incorporation into the EPE system of customer-sited microgrids. The customer-sited microgrid will, at the very least, consist of a battery and a generating resource. Such a system can be utilized by EPE in two fashions. First, much like the other battery DR programs discussed above, EPE will be able to access the customer battery based on system need. Additionally, with the incorporation of a demand energy resource management system (DERMS), EPE will be able to communicate with the customer's microgrid, analyze the customer's specific distribution network, and utilize the customer's microgrid to resolve any larger system or local distribution issues. By allowing EPE to actively manage the usage of the battery and on-site generation, it will help the customer to reduce their demand and impact to the grid while providing an additional tool in EPE's reliability belt.

Based on the above, it should come to no surprise that EPE believes that as least in the non-ERCOT areas utilities are the best entities to develop and manage demand energy response programs. We are aware of the current needs of the system, future demands on and changes to the system, and, most importantly, the second-to-second changes on the system that would necessitate the use of DERs. Moreover, as every utility's distribution system is unique and ever changing, it makes sense that the utilities responsible for the operation of those systems will be the best at tailoring DER solutions that cost-effectively benefit the customer and the system. Plus, given the vulnerabilities presented by cyberattacks, placing additional customer-sited resources onto the system should be handled by those entities tasked with securing that same critical infrastructure. Innovation and growth in this new arena will not be hindered as long as the utilities are provided clear guidance as to how such programs will be approved. The communication of clear policy goals and the metrics by which they will be measured will help the utilities identify what resources are best for the system and provide the developers of DER technology the information necessary to develop products that meet those system needs. Customers will benefit from this relationship as this

[2] Heavy-duty vehicles charging can create demand spikes as high as 2MW per vehicle and be an equivalent of the average annual usage of 17 residential customers in EPE service territory, according to EPE's Economic Research Report, June 2020

model will ensure customers will have access to resources that are subject to the judicious oversite that currently protects them. Additionally, as such DER programs would have to prove system benefit to the Commission and any subsidy, whether they be through net energy metering, bill credits, or discounted DER systems, will be subjected to rigorous analysis to ensure that the utility and its customers are receiving the promised benefits.

ii) *Should the current size limit on unregistered distributed resources be reconsidered?*

Response:

EPE has no comment on this question.

2) ***Transmission and distribution modification:*** *What equipment, processes, and standards need to be implemented to allow for further DER participation?*

Response:

EPE currently has a simple, yet effective process to handle interconnection requests for residential and small commercial customers that processes on average 500 to 600 interconnections per month, but such practices may need to change as the technology and demands placed on the system change. Plus, as mentioned earlier, standards may need to vary for each utility's specific circumstances.

Currently, DERs do not present a risk to EPE's distribution, transmission, or generation resources. However, as penetration increases there will be significant risk to reliability, resource allocation, and distribution lines and equipment requiring significant upgrades or additions. Proper planning will ensure that DER is smoothly interconnected to the system without unnecessary delays or risks to the system.

Finally, as discussed above, clear and proper rate recovery mechanisms for necessary distribution and transmission upgrades are essential to further advance the participation of DER in Texas. These regulatory mechanisms will also have to consider the unique needs of and different rules placed upon each utility. Additionally, it may need to provide for flexibility as new technologies are developed.

3) ***Cost quantification:*** *How much transmission and distribution investment will be necessary and what methods would be available to recuperate costs? And should the Commission consider new methods of cost allocation and recovery for DER-related infrastructure*

enhancements?

Response:

EPE has not quantified how much transmission and distribution investment is necessary. The amount of investment will be dependent on the quantity and sizes of the future interconnections. Interconnection costs and related upgrades are the customer's responsibility. Should the Commission decide not to require costs to be borne by the entity necessitating any system upgrades, then the distribution cost recovery factor (DCRF) and transmission cost recovery factor (TCRF) are currently available to allocate costs among all customer classes. The Commission may, however, consider developing a separate mechanism for analyzing the cost recovery of DERs.

EPE recommends that the Commission reference the Distributed Energy Resources Rate Design and Compensation manual prepared by NARUC (November 2016), MIT's report (December 2016) titled "Utility of the Future", and the National Energy Screening Project's "National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources" (August 2020). These documents have important discussion on DER and cost recovery mechanisms.

i) *What market signals, if any, should be considered related to DERs aimed at providing grid services?*

Response:

This question is more relevant to the market in ERCOT, of which EPE is not a participant. However, to the extent payments to DERs would be made for services to the grid, those payments should be based on avoided costs and benefits to the system. Payment should be dependent on the value of the energy exported to the grid, value of voltage support, and any other benefit provided to the grid.

4) ***Data accessibility:*** *What data would improve supply side dynamics and encourage targeted development? What information would be useful to establish a current baseline and assess future market potential? What accessibility and information security concerns should be considered?*

Response:

A high penetration of DER systems needs to increase the power supply and demand balancing capability in an electric power system or a specific geographical segment thereof, for example the installation and/or location of batteries at the substation level. For the best use of balancing capability, highly accurate and reliable forecasting methods, contingent on the DER technology, would play a very important role in various time horizons from several hours-ahead to several days-ahead. An accurate and reliable forecasting method should be employed not only in the power system but also in an individual energy management system; it is critical for utilities, customers, and third parties to coordinate and facilitate two-way data exchange. An application of DERs would be to manage a utility's load curve, for example to facilitate peak shaving. DERs may also generate power during peak demand hours and hours when utilities are capacity constrained. DERs contribution to meeting peak demand would be useful to establish a current baseline and assess future potential subject to system constraints. It would be important to specify the requirements for non-utility, DER performance, and the consequences for not meeting those requirements. Energy management system data feeds to facilitate control strategies for DER systems and their cyber security (e.g., energy storage systems and smart meters) would be items for consideration.

i) *What level of information should entities responsible for planning and control of DERs have access to for long-term planning purposes?*

Response:

For long-term planning purposes, utilities will need nameplate capacity, location, power and energy production, generation profiles, and technical life of the DER. For renewable technology DER(s) such as solar or wind, utilities will need high resolution temporal (sub-hourly) generation and spatial data to account for the inherent stochastic nature and geographic diversity of the DER.

5) ***Other related questions***

i) Should the Commission consider classifying various DER types? If so, on what basis should DERs be classified? For example, size, performance, characteristics, or some other attribute? (E.g., rooftop solar PV, distribution connected energy storage, microgrids)

Response:

At this time, the DER classifications should be in generally broad categories: distributed generation, energy storage, and demand response. Classification by size (e.g., nameplate ratings) is important in a resource planning sense and for alignment with different screening processes or rules.

ii) What issues should be considered for segmentation and islanding? Should there be consideration related to DERs associated with critical facilities and entities?

Response:

There are many issues that should be considered for segmentation and islanding. This would be best address during utility and industry workshops to fully discuss and understand issues around islanding. This would also include discussions concerning customer protections, power quality, and system protections. Additionally, the Commission should consider approving pilot projects to assess the real-world impacts of such programs.

iii) What should be done to encourage consistency in interconnection agreements between the various interconnecting entities?

Response:

The Commission should take up the development of draft agreements and share them with the utilities for initial feedback. Once the utilities find alignment on the revised draft agreements, the final draft should be shared with all stakeholders for additional feedback. This may help expedite the development of the interconnection agreements. Other states have opted to open it to all stakeholders which have caused lengthy proceedings with mixed results. It is important to keep in mind that any such agreements must accommodate each utility's unique circumstances.

iv) What can the Commission do to promote consistency in its DER policy between the ERCOT and non-ERCOT markets?

Response:

The Commission should try to be consistent as far as reasonably possible, however, it should also be aware that each utility within and outside ERCOT have their individual difference in the respective systems and markets. There could be some consistency on interconnection rules or along broader policy goals like reliability.

v) What successes have been seen in other states that could be implemented in Texas?

Response:

Multiple states are addressing how to incorporate DER into their systems while considering the interest of various stakeholders regarding cost recovery. EPE believes that the Commission should consider actions taken by other states to reduce regulatory lag and facilitate quicker recovery of investments. Most importantly, the Commission should review and develop its own methodology for assessing and approving DER.

In regards to reducing regulatory lag, the Public Service Commission of Utah allowed Rocky Mountain Power (RMP) to file an annual report adjusting the compensation paid to distributed generation customers for their excess production (Docket 17-035-61). The annual updates do not impact the rates an RMP customer pays for electricity service, which obviated the need for a litigated filing. RMP believes the ruling helped them reduce fees caused by net metering passed on to non-net metering customers. A similar tack could be taken in Texas when it comes to payments for customers' distributed generation.

More broadly speaking, EPE suggests that the Commission review the methods by which other states review DER programs. Other states have opted to review DER programs through some variation of a benefit-cost analysis instead of the standard lowest cost analysis.[3] What will be crucial for this Commission to determine is what policy goals it wishes to achieve through the incorporation of DER, which will then inform the methodology for measuring success. For example, should this Commission believe that resiliency for the system and customers is a policy goal, a metrics will have to be established to measure those benefits or achievements and appropriate allocations of costs will have to be determined based on which customers benefit.

vi) What can reasonably and economically be done within a 5-year timeframe?

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[3] Please refer to the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, August 2020, for a general analysis of establishing a framework for reviewing DER programs. A summary of how states currently review energy efficiency programs is included. (https://nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs08-24-2020.pdf).

Response:

Over a five year horizon, the Commission can reasonably create a framework for measuring the effectiveness of DER programs. This analysis will provide both utilities and the market with the certainty needed to incorporate DER into a utility's system. A framework like this is important, as discussed above, because each utility is unique but the broader policy goals like reliability are the same across systems. With that framework in hand, utilities will more readily propose programs, which in turn will give the Commission the data to measure the impacts and effectiveness of DERs on the system. Additionally, as the Commission is merely setting a framework and not selecting a technology, innovation in the DER sector will not be hindered and utilities will be able to stay apace of technological changes.

vii) What other issues, if any, should the Commission consider and address while developing rules related to DERs?

Response:

EPE believes at this time the responses above cover the issues that it deems important for the Commission to consider in developing DER rules.

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EL PASO ELECTRIC COMPANY'S EXECUTIVE SUMMARY TO QUESTIONS FROM COMMISSIONERS MCADAMS MEMORANDUM

El Paso Electric Company (EPE or the Company) appreciates the opportunity to answer the Commission's questions regarding this important topic. The Company believes that distributed energy resources (DER) will only continue to grow; therefore establishing a framework to review DER is paramount to ensuring system reliability and a fair cost allocation. Any regulatory mechanism, however, must take into consideration each Texas utility's unique system and rules in order to be effective. As such, EPE believes that an initial step for the Commission in establishing DER rules would be to define commonalities in DER practices (e.g., interconnection agreement terms) and broader policy goals and their associated metrics that are common to all Texas utilities.

EPE believes that the current regulatory model in which the Commission reviews and approves programs should apply to DER as it will ensure (1) the safety and reliability of the system and (2) the appropriate cost allocations exist and are reflective of both the costs and benefits DER provides the system and its customers. As such, utilities are best situated to develop and administer DER that boasts system benefits that offset any costs associated with them. It is utilities and not third parties who are most familiar with their existing systems, rules, and the second-to-second changes that occur within them; are best situated to analyze and preliminarily assess system benefits; and, even more importantly, are already familiar with maintaining the security of the system from both physical attacks and cyberattacks. Innovation will not be hampered as long as clear, policy-based metrics are defined for approving and recovering on investments in DER.

In EPE's opinion, the Commission can reasonably begin the needed workshops and discussions to facilitate establishing those common DER issues faced by all utilities. The Commission can begin the process of analyzing interconnection agreements to determine what common language needs to be present for Texas utilities. Additionally, it can begin the process of analyzing the various types of DER (distributed generation, demand response, and energy storage), their impacts on the system, and best practices for each through workshops. And finally, the Commission can start to define the policy goals it seeks to achieve through DER and how those goals should be measured in order to ensure continued innovation that does not come at the expense of reliability or by unduly taxing the wallets of ratepayers.