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

THE AEP COMPANIES' COMMENTS ON COMMISSION STAFF'S QUESTIONS

AEP Texas Inc. and Southwestern Electric Power Company (collectively, the AEP Companies) respectfully provide the following written comments on the questions that the Staff of the Public Utility Commission of Texas ("Commission") filed in this project on May 1, 2022 related to distributed energy resources ("DERs"). AEP Texas is a transmission and distribution service provider ("TDSP") operating in the Electric Reliability Council of Texas ("ERCOT") region. Southwestern Electric Power Company is a vertically integrated utility operating in Texas and is a member of the Southwest Power Pool, Inc. ("SPP"). The AEP Companies appreciate the Commission's work on these important issues and the opportunity to provide comments.

A threshold matter in identifying relevant DER issues for this project is to define "DER." Although "DER" is a common term in the energy industry, there is no clear consensus among industry stakeholders on the definition of "DER." For example, the North American Electric Reliability Corporation ("NERC") has defined "DER" as "Any Source of Electric Power located on the Distribution System."[1] The Federal Energy Regulatory Commission ("FERC") has defined a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter."[2] SPP proposed a similar definition.[3] While the Commission's rules include definitions of some components of DER,[4] currently there is no definition of the term "DER" in the

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[1] *See* North American Electric Reliability Corporation, Quick Reference Guide: Distributed Energy Resource Activities (June 2022) available at Document Landscape (nerc.com).

[2] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247, P 114 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g and clarification*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

[3] *Southwest Power Pool, Inc.*, FERC Docket No. ER22-1697-000, Compliance Filing of Southwest Power Pool, Inc. at 6-7 (Apr. 28, 2022).

[4] *E.g.*, Distributed Generation ("DG"), Distributed Renewable Generation, Distribution Energy Storage Resource, Distribution Generation Resource, and Settlement Only Distribution Generator.

Commission's rules. The Commission's rules do define "Distributed Resources" as "a generation, energy storage, or targeted demand-side resource, generally between one kilowatt and ten megawatts (MW), located at a customer's site or near a load center, which may be connected at the distribution voltage level (below 60,000 volts), that provides advantages to the system, such as deferring the need for upgrading local distribution facilities."[5] Under the various definitions, DERs can include, but are not limited to, distribution generation, energy storage, energy efficiency, demand response, electric vehicles and their charging equipment, and load management. Sharing a common definition will help provide a framework for future discussions in this project, and being mindful of the various definitions will be important to the extent the Commission wishes to encourage consistency in its DER policy between the ERCOT and non-ERCOT markets.

I. COMMENTS

1. <u>Distribution planning and control:</u> 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?

In recent years, the Texas ERCOT market has seen significant growth in the number of DER interconnects. There are nearly 3 gigawatts of distributed generation resources in ERCOT with 740 MW added in 2021 alone.[6] DERs have the capability to reduce load or supply energy to the grid. This represents a change from the traditional utility model, as one-way flows are reduced and two-way power flows are introduced, which can affect the reliability and resiliency of the distribution grid. Accordingly, as more DERs connect to distribution wires, there will be a corresponding need for increased visibility into, real-time monitoring of, and control of these assets. The interconnecting utility must be involved in the planning and control processes because it has the obligation to serve and maintain system reliability and customer quality of service. Distribution utilities monitor and study injectable, reliable energy supplied to the grid from DERs separately from DERs used for load reduction programs. The Commission may also consider how the applicable regional transmission organization ("RTO") should be involved in the planning and

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[5] 16 Tex. Admin. Code § 25.5(32).

[6] *Review of Wholesale Electric Market Design*, Project No. 52373, Commissioner McAdams Memorandum (Apr. 20, 2022).

control processes, considering, for example, that DERs may not be equally valuable to the grid in all locations and that their performance may affect the reliability and operations of the bulk power system. The Commission may also consider rulemakings and additional ERCOT protocol and guide changes that would affect both DER participation and grid reliability and resilience.

Some other issues related to planning and control processes and practices the Commission could consider to maintain and enhance the reliability of the transmission and distribution system as DER penetration increases include:

- <u>Consider the effects of increasing DERs on a utility's under-frequency and under-voltage load shed (UFLS and UVLS) schemes.</u> ERCOT is responsible for ensuring the reliability of the electrical system, which includes maintaining a balance between the power generated and consumed and working to keep system frequency and transmission line voltages within acceptable levels. Electric utilities operating within the ERCOT system must establish and maintain at least 25% of their Transmission Operator's load to automatically shed when system frequency or voltage drops below required levels. The under-frequency settings are enabled or disabled on-site at selected circuit-breaker controls located within the substation. DER interconnection penetration in either volume or capacity will make managing UFLS and UVLS schemes more difficult. DERs' generation output may vary widely from hour to hour, which can affect the ability to maintain required levels of load shedding based on frequency or voltage. For example, the first stage of UFLS must be maintained to shed a minimum of five percent of the Transmission Operator's load at the time of the event. When DER output level is high on UFLS feeders, more feeders may need to be added under UFLS supervision to achieve the TDSP's five percent requirement because the net load on existing UFLS feeders is low compared to instances when the load was measured while several or all of the DERs were off. To compensate for this, TDSPs may add more feeders to their UFLS plan. However, considering this new UFLS plan with added feeders, when DER output is low and net load high, and with more feeders having now been added to the UFLS program, there is a risk that the first-stage load shed may be much higher than the five percent requirement, which increases the risk of over-shedding and causing frequency overshoot. Similar issues exist for UVLS schemes. The ability of DER to ride through frequency and voltage disturbances also affects how the UFLS and UVLS schemes would need to be maintained and any uncertainty on DER ride-through capabilities will contribute to the risk of over- or under-shedding of load. In addition, the Commission could consider how to properly balance the reliability-related operations requirements aimed at maintaining a sufficient percentage of UFLS and UVLS across wires companies in ERCOT.

- Ensure that TDSPs have supervisory control override capability at the point of interconnection. Such capability is critical for the interconnecting utility to properly isolate any DERs identified as creating real-time reliability or power quality disturbances for the customers served from the distribution system in that area.
- Consider limiting DERs to a single tariff or service for a one-year minimum. Such a requirement will reduce the real-time decision-making impact associated with DERs continually changing service types, which affects how DERs are viewed in real-time contingency analysis. Each change in service type will cause additional work related to setup, configuration, and modeling in the real-time monitoring systems/tools.

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

The participation formats for DERs on the AEP Companies' distribution systems are:

AEP Texas	Southwestern Electric Power Company
• Distribution Generation Resources; • Distribution Energy Storage Resources; • Settlement Only Distribution Generators; • Residential applications.	• DG at commercial customer sites that may be operated as a microgrid; • DG greater than 10 MW at cogeneration sites; • Residential applications.

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

The current size limit (i.e., below 1 MW) on unregistered distributed resources in the ERCOT region is appropriate at this time. For calendar year 2021, ERCOT reports 1,358.66 MW of unregistered DG installed capacity in the region's eight load zones.[7]

[7] See Generation (ercot.com).

2. <u>Transmission and distribution modification:</u> What equipment, processes, and standards need to be implemented to allow for further DER participation?

As noted in response to Question 1, the increasing presence of DERs on the system will introduce new reliability and resiliency issues that will require the consideration of new equipment, processes, and standards to allow for further DER participation. Monitoring, metering, telemetry, bidirectional devices, and reclosing/curtailment devices are examples of equipment that will become increasingly important to maintain grid balance and reliability, and this equipment will need to tie together with existing operational and support systems to model and forecast effects of DERs on the system. Additionally, backend and headend systems will be needed for data integration of devices and equipment on the distribution and transmission systems.

- <u>Consider updating technical performance standards and specifications.</u> The Commission could consider updating DER performance standards, modeling requirements, and data requirements to help minimize the impact of DER interconnections on customer, distribution, or transmission reliability. Similarly, the Commission could consider updating operational requirements and incorporating them into interconnection standards to help ensure distribution and transmission grid reliability, including proper voltage and frequency disturbance ride-through capabilities. The IEEE Standard 1547™-2018 was published in pursuit of this objective, and multiple states have adopted, referenced, or used the IEEE Standard 1547™ to develop their own interconnection rules.[8] According to the National Renewable Energy Laboratory, the IEEE Standard 1547™ provides functional technical requirements that are universally needed to help ensure a technically sound interconnection.[9] Functional requirements "allow flexibility and innovation and state the required outcome, not how to achieve that or the equipment or methods that must be used to satisfy the requirements."[10]

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[8] Thomas Basso, Nat'l Renewable Energy Lab., IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid at 2.

[9] *Id.* at 4.

[10] *Id.*

- <u>Other questions the Commission could consider are:</u>
  - o Should distribution circuit hosting capacity limits based on circuit operating voltage level be established?
  - o Should distribution circuit minimum contingency levels for distribution system impact studies be established?
  - o Should the Commission pre-certify DER equipment?
  - o Should there be common interoperable protocols to increase coordination between DERs, aggregators, and system operators?
  - o Evaluate the appropriate DER size threshold for requiring real-time telemetry data.
  - o Should the Commission encourage and support the implementation of Advanced Distribution Management Systems ("ADMS") and operational Distributed Energy Resource Management System ("DERMS") to manage higher penetrations of DER to ensure safe and reliable system operations?
  - o Consider the benefits of utility ownership of DERs that enhance the reliability of the distribution system.
  - o Should DER be held accountable for the performance and reliability of facilities?
  - o Consider the costs and benefits of grid-modernization investments to add or enhance system capabilities and architecture related to visibility, real-time monitoring, and control of distribution devices.
  - o Should the Commission consider allowing utilities to establish, and customers to participate in, distribution reliability-focused programs that allow utility interface with customer-owned DER equipment for reliability purposes?

3. <u>Cost quantification:</u> 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?

Transmission and distribution spending to facilitate DERs will generally fall into three categories: (1) hardware costs (e.g., metering, telecommunications, general infrastructure, ADMS, and interconnection upgrades); (2) information technology and operational technology software costs (e.g., updated billing and customer tracking systems, modeling upgrades to incorporate DER and Distributed Energy Resource Aggregation forecasts and behaviors into studies; ADMS with operational-side DERMS functionality); and (3) administrative costs (e.g., staff and analytical support are needed to accommodate incremental volume of interconnection requests and the increasing complexity of DER interconnection studies and real-time operations). Because the future of DERs depends on multiple variables, the AEP Companies have not quantified the level of investment needed in Texas at this time. The AEP Companies note, however, that the increasing presence of DERs presents some complex cost recovery and cost allocation issues, including, for example, issues raised by the fact that the cost structures of various types of DERs vary and that DERs may have both retail and wholesale characteristics that will need to be individually studied to determine if that DER investment may benefit the system, rather than a more limited, localized area.

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

The AEP Companies do not have any comments on this issue at this time.

4. <u>Data accessibility:</u> 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?

Supply side dynamics and targeted development could be improved by providing policy certainty, so that market participants understand the costs and benefits of providing DERs. In the ERCOT Region, the Commission could use existing DER data from various market stakeholders to establish a current baseline for DER penetration and market participation. To assess market potential and risk, the Commission would need to evaluate and understand the drivers for customers to install and operate DERs, and to potentially participate in the wholesale market.

DER information should be disaggregated from customer load and availability because if there is a single meter capturing the combined behavior of a customer load and customer DG, it becomes difficult to assess the performance of the DG. Deploying separate sub-metering for DERs helps remove this hurdle. The capability of DERs participating in wholesale market activities needs to be clearly visible to dispatchers to avoid a DER being counted as both a load reducer and a generation resource and to help plan and operate the system in real time. Utilities would also benefit from knowing which wholesale market service each DER is providing so that it can more effectively plan and operate its distribution and transmission system. Finally, the Commission should consider the proper balance between data accessibility and security. DERs may rely more heavily on digital computing and connectivity, which could implicate privacy concerns and make them more visible targets.

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

As entities responsible for planning and control of distribution and transmission systems, with increased penetration of DERs, electric utilities need accurate, granular historical and real-time data to develop system models, validate results, and perform real-time and long-term analysis and planning. The Commission could consider whether the interconnection, operations, and planning processes for DERs could be better aligned with those of large generators connected to the transmission system. The Commission also could enhance the utility's visibility into DERs participating in the market and utilities should have access to more granular information regarding aggregation of DERs in the market.

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)

Yes, the Commission should consider classifying various DER types. The term "DER" can refer to a broad range of operational assets for electricity generation, energy storage, load management, and various types of control systems that connect physically to the electricity system at the distribution level rather than to the bulk power system. For example, the Commission could consider classifying DERs based on their point of interconnection to the power system. DERs may connect either directly to the distribution utility's network (front-of-meter DERs) or to the electrical system on a customer's premises (behind-the-meter DERs). Also, DERs could be classified based on their technology, size, and services that can be provided. Although some of these DER types already are defined in the ERCOT Region, evolving technologies and desired participation levels in various markets may warrant updates to existing definitions.

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

Intentional islanding can be beneficial to supporting grid reliability, while unintentional islanding of grid-connected DERs can pose increased risk and operational challenges to grid operators. The AEP Companies note that IEEE Standard 1547™-2018 addresses both intentional and unintentional islanding of DERs.

Yes, there should be consideration given to DERs associated with critical facilities and entities, including an evaluation of DERs installed at critical facilities and their participation in wholesale market services.

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

The AEP Companies support the Commission's desire for consistency in interconnection agreements. To that end, the AEP Companies note that Commission Staff has tasked a small group of interested stakeholders to begin working toward a standardized agreement template similar to the standard generation interconnection agreement ("SGIA") in use for transmission-interconnected resources.

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

The Commission could consider monitoring DER development in other RTOs and/or conducting a workshop where lessons from other states and RTOs can be evaluated. The AEP Companies urge the Commission to promote consistency between its policies, rules, and procedures with the measures being implemented in the SPP in support of DER aggregations.

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

As DER technologies advance rapidly, a state-approved list of customer DER equipment would significantly speed up reviews and installations, as has been done in California.[11] However, it would be equally important for the Commission to understand challenges that other states have

[11] Rule 21 Interconnection (ca.gov).

faced in implementing DERs. The Commission could conduct a workshop to further investigate the successes and challenges faced by other states.

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

Within the next five years, electric utilities and RTOs can develop robust processes to identify DERs on the system and their intended usage that would enable proper modeling of the DERs' behavior. Transmission and distribution planning and operations can continue to develop accurate modeling of DERs in planning studies to identify opportunities and challenges to bulk system and distribution system reliability in terms of voltage and frequency performance.

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

- Consider the benefits of and potential need for customer education programs on DERs.
- Consider exploring options to address consumer protection issues with respect to residential DER applications.

II. CONCLUSION

The AEP Companies appreciate the Commission's consideration of these comments and look forward to participating in future discussions with interested stakeholders on these important issues.

Respectfully submitted,

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ON BEHALF OF AEP TEXAS INC. AND SOUTHWESTERN ELECTRIC POWER COMPANY

The AEP Companies' Executive Summary of Comments to Questions Related to Distributed Energy Resources

The AEP Companies appreciate the Commission's work on distributed energy resources ("DERs") and the opportunity to submit comments. The questions posed raise many important issues that would benefit from thorough consideration and additional feedback from interested stakeholders. Accordingly, it would be beneficial for the Commission to host a series of technical work sessions to address the issues raised by the comments filed in response to Staff's questions.

- <u>Distribution Planning and Control:</u> While DERs can offer many benefits, the proliferation of DERs can also affect the reliability and resiliency of the distribution grid and the bulk power system through impacts to operations and planning. Many of these issues can be effectively managed by allowing increased visibility into, real-time monitoring of, and control of these assets.
- <u>Transmission and Distribution Modification:</u> A variety of new equipment, processes, and standards should be considered, including technical performance standards and specifications. Focusing on functional, flexible requirements may be beneficial considering the rapid development of DER technologies. Multiple states have adopted, referenced, or used the IEEE Standard 1547™ to develop their own interconnection rules. A variety of technical questions deserve detailed consideration.
- <u>Cost Quantification:</u> There are many cost issues that the Commission needs to consider in relation to deployment of DERs. Interconnecting utilities will incur several categories of costs to facilitate DERs, although the costs have not been quantified at this time. In addition, DERs present many complex cost recovery and cost allocation issues that warrant further discussion.
- <u>Data Accessibility:</u> Utilities need accurate, granular historical and real-time data to develop system models, validate results, and perform real-time and long-term analysis and planning. A more thorough discussion on data sharing is warranted, especially given security concerns.
- <u>Other related questions:</u> With many types of consumers with varying levels of sophistication investing in DERs, the Commission should consider whether and how to advance consumer education and protection measures. Considering that several Texas utilities operate in areas outside of ERCOT, the Commission may wish to review DER policies in use in other states or RTOs to promote consistency for utilities across the state.