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Public Utility Commission of Texas
1701 N. Congress Ave.
PO Box 13326
Austin, Texas 78711-3326

RE: Project No. 51603 – Comments of CPS Energy to Review of Distributed Energy Resources

Dear Central Records,

Please void items number 35 in Project 51603 as the document did not contain the electronic signature for Mr. Gabriel Garcia.

Thank you,

Belen Cervantez
Belen Cervantez
Legal Program Manager

PUC PROJECT NO. 51603

REVIEW OF DISTRIBUTED ENERGY RESOURCES	§ § § § §	**BEFORE THE PUBLIC UTILITYCOMMISSION OF TEXAS**

COMMENTS OF CPS ENERGY

TO THE PUBLIC UTILITY COMMISSION OF TEXAS:

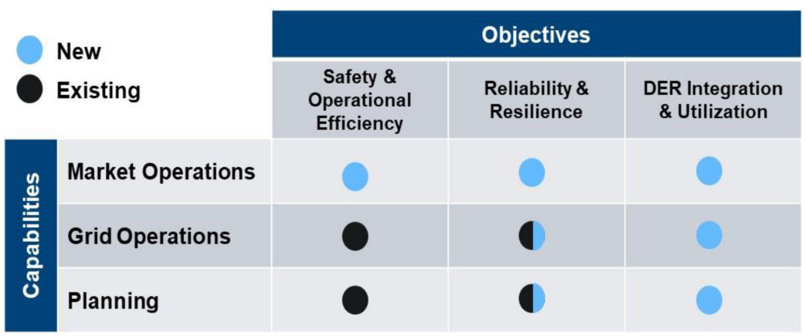
COMES, NOW, the City of San Antonio, acting by and through the City Public Service Board (CPS Energy), and files these comments in response to questions posted on April 29, 2022. intended to solicit a general survey of issues and positions related distributed energy resources (DERs). The deadline for this filing is June 15, 2022, therefore, these comments are timely filed.

I. INTRODUCTION

The questions raised to solicit opinions on advancing the deployment of DERs within ERCOT should be framed in the context of grid modernization. The integration and utilization of DERs is but one of several objectives of a modern grid.[1] The three objectives of grid modernization are (i) safety and operational efficiency; (ii) reliability and resilience; and (iii) DER integration and utilization. Each of these objectives is supported by related business functions and technologies that work together to enable and expand existing and new capabilities. With grid modernization, technologies are implemented to expand existing capabilities and create new capabilities, which include distribution planning, grid operations, and market operations.

Figure 1 illustrates the objectives of grid modernization in relation to grid capabilities. As the figure demonstrates, the capabilities of planning, grid operations, and market operations associated with DER integration and utilization will not materialize without grid modernization. Therefore, DER integration and utilization should not be viewed in isolation, but as a necessary component of grid modernization – a technology upgrade process that is specific to individual utility situations and must be aligned with the pace and scope of specific customer needs, jurisdictional objectives, and value for all customers.[2]

Figure 1: Objectives of Grid Modernization in Relation to Grid Capabilities[3]



In addition, ERCOT has determined that opening the wholesale markets to participation by aggregations of distributed-connected small commercial and residential loads by Aggregate Load Resources (ALRs) will require development of alternative network modeling. For this reason, ERCOT placed limitations on the initial rollout of ALRs "…to avoid system degradation (which could occur if large numbers of ALRs begin are participating) and potential challenges to effective congestion management and grid reliability (due to dispersion of participating Loads with

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[1] *Modern Distribution Grid (DSPx), Vol. I: Objective Driven Functionality*, Version 2.0, U.S. Dept. of Energy, Office of Electricity (hereinafter "*Modern Distribution Grid*"). ("In concept, the starting point of a modern grid is a foundation built upon enhancements to safety and operational efficiencies, as well as reliability and resilience. This is augmented with new functions and technology to support grid resilience as well as to enable DER integration and utilization for grid services in line with the timing, scale, and scope of customer adoption and value for all customers." *Modern Distribution Grid* at 10.) Document available at: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_I_v2_0.pdf.

[2] *Id*. at 11.

[3] *Id*.

insufficient locational specificity)." ERCOT expects that full participation of ALRs will require changes to its market rules and potential amendments to PUC substantive rules, as well as significant ERCOT system upgrades.[4]

Accordingly, we support policies to enhance the deployment of DERs consistent with promoting the safety, reliability, resiliency, and operational efficiency of our distribution system, as well as the proper recovery of costs associated with the use of distribution system to reach the transmission grid. These comments are developed focusing primarily on unregistered DERs of less than one megawatt (MW) connected behind-the-meter of a small commercial or residential retail customer's premises. Larger DERs greater than one MW but less than ten MW registered with ERCOT as settlement-only distributed generation (SODG) interconnected at distribution voltage, in our experience, require more sophisticated interconnection requirements that should be addressed in a separate rulemaking proceeding.[5]

To be most effective and cause the least amount of disruption we believe any policies adopted by the Commission should follow the following guiding principles:

- The safety and reliability of the distribution system is top priority.

- The integration of DERs should follow these steps: (i) develop an appropriate definition of DER; (ii) establish technical limitations and requirements to allow DERs to operate safely and reliably, and (iii) identify technology upgrade costs to distribution and transmission systems necessary for the integration of DER technologies.

- Guidelines and best practices should be developed in a collaborative manner avoiding undue regulatory burden on distribution systems.

- Recognize that distribution system operators have an appropriate level of autonomy which should be preserved to fulfill their service delivery obligations.

- Recovery of distribution costs and rate implications of integrating DERs should not be a focus of this exploratory project. Under the current legal structure, recovery of such

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[4] *Requirements for Aggregate Load Resource Participation in the ERCOT Markets, Version 1.3*, ERCOT Other Binding Document (OBD), Effective Date: 9/1/20, at 11 (hereinafter, "ALR Best Practices OBD"). An ALR must meet qualifications for participation in Security-Constrained Economic Dispatch and the provision of Non-Spinning Reserve service. ALR participation in the ERCOT markets is limited to (i) system-wide capped at 250 ALRs; and (ii) the combined demand response capability of all ALRs within a single ERCOT Load Zone capped at 5% of the Load Zone's highest historical summer peak demand. If these caps prove insufficient to prevent an operational challenge, ERCOT will work with stakeholders to determine appropriate changes and seek their expedited approval. In addition, an ALR must meet several requirements, including registration, QSE representation, metering functionality, telemetry validation, and network modeling, as well as meet qualifications to provide Non-Spin. Document available at: https://www.ercot.com/files/docs/2020/08/31/Requirements_for_Aggregate_Load_Resource_Participation_in_the_ERCOT_Markets.doc.

[5] See diagram of Distributed Generation in ERCOT distinguishing between unregistered Distributed Generation and registered Settlement Only Distributed Generation and Distributed Generation Resources. Document available at: https://www.ercot.com/files/docs/2020/06/03/DG_and_DR_in_ERCOT_FINAL2.pdf.

costs will be through traditional rate case proceedings as authorized by the applicable jurisdictional authorities.

We submit the answers to the questions posed by the Commission below.

II. CPS ENERGY RESPONSES

Distribution Planning and Control

Q: What is a reasonable level of planning and control that will contribute to greater DER participation and greater resilience?

While all distribution systems follow a similar set of technical operational standards, each distribution system needs visibility regarding all its connected DERs to be able to independently plan for and properly integrate them. Compared to the transmission grid, the distribution system is much more dynamic and complex. The distribution system is constantly growing and changing with the addition of new housing and commercial developments as well as redevelopments.

Distribution systems are also frequently reconfigured for a variety of reasons, such as during certain maintenance events and unplanned outages due to faults. During these events the distribution system is redesigned by switching distribution circuits to minimize customer impacts. These temporary configurations, or "abnormal" circuit conditions, may last a few hours, such as when a vehicle striking a pole, but could last for weeks or months following major storms.

Outages and abnormal circuit configurations can create capacity constraints within the distribution system, which would in turn will affect a DER's ability to participate in the wholesale markets. Depending on distribution system loading or voltage conditions, DERs may need to be ramped up or curtailed if thermal or voltage violations occur, or in response to circuit reconfigurations. To integrate DERs, distribution systems will require upgraded equipment and new technologies to be able to manage voltage irregularities and have real-time visibility into DER status. All of which is necessary for DERs to provide coordinated demand response contributions to the distribution system or wholesale market services.[6]

A similar lack of coordination between larger distributed generating facilities (interconnected at the transmission level) and the bulk power system can also cause grid instability. While it may be tempting to seek to apply the current ERCOT transmission planning process to distribution systems, we believe the dynamic nature of the distribution system makes this unfeasible. The current framework for distribution system planning augmented with smart grid technologies to provide real-time visibility into DER conditions will be necessary to integrate DERs.

Q: What level of remote, granular controllability is possible?

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[6] *The Potential of Distributed Energy Resources in ERCOT, and the Importance of Getting It Right*, Cox School of Business, SMU, Aug. 2020, Bernard L. Weinstein and Nicholas J. Saliba, at 15. Report available at: https://www.smu.edu/-/media/Site/Cox/CentersAndInstitutes/MaguireEnergyInstitute/ONCORNWAFinalReport7-27-20.pdf?la=en.

Given the dynamic nature of the distribution system and need to maintain its safety and reliability, distribution system operators will need to exercise control over DERs interconnected at the distribution level to plan for their orderly deployment. By necessity, this must include the ability to curtail the DER if its energy production creates a safety or reliability concern for the system. By way of illustration, consider a DER located behind-the-meter at a residential or small commercial site that experiences an outage. If the DER continues unabated to energize the premises and related distribution equipment, it may present a hazard to the crews working to correct the outage. Or consider a fire at the same premises. If the DER is not deenergized, live wires at the premises will present an even more dangerous hazard to first responders. These considerations amplify our position that only trained CPS Energy crews should work on our distribution system, regardless of the future level of DER proliferation. Addressing these concerns is critical to the safety of CPS Energy crews and community first responders.

The safety and reliability of the distribution system is paramount to CPS Energy and DER participation must take place through the adoption of processes and technologies that abide by having controls in place to provide customers with safe and reliable electricity service. For this reason, CPS Energy has developed its own Distributed Generation Manual (DG Manual)[7] applicable to all DERs interconnected behind-the-meter at the distribution level. The DG Manual set out technical interconnection and equipment standards, among other items.

Q: Presently, how are existing DERs utilized on distribution networks?

Over the last 20 years, CPS Energy's regulatory authority, the San Antonio City Council, has approved investments in infrastructure and in the creation of several demand response programs with rate payer support that have substantially increased the adoption of DERs within our service area. These investments and programs fall into three major categories: (1) deployment of automated meters; (2) adoption of utility-scale renewable generation; and (3) demand response and energy efficiency programs.

CPS Energy began its deployment of smart meters in 2013 and completed the installation in 2018 at an investment of $290 million.[8] Under our current DG Manual, we require every DER to have its own smart meter installed. This investment in smart meters would facilitate the participation of DERs in the ERCOT wholesale markets.

CPS Energy began investing in utility-scale renewable generation in 2000 and today renewable energy resources represent 22% of our generation capacity. This investment includes 100 MW in solar farms located within the distribution service area, of which 1 MW is dedicated to community solar projects. Further, CPS Energy owns 20 MW of distributed energy storage, which is used to shift power to high demand periods with excess capacity participating in the ERCOT wholesale markets at other times. We expect to procure an additional 50 MW of energy storage as part of our Flexible Path generation strategy.

[7] CPS Energy's Distributed Generation Manual is available at: https://www.cpsenergy.com/content/dam/corporate/en/Documents/Distributed%20Generation%20Manual.pdf.

[8] *CPS Energy Rolling Out Smart Meters, San Antonio Report*, Aug. 16, 2014 by Iris Dimmick. Article available at: https://sanantonioreport.org/cps-energy-roll-smart-meters-next-week/.

CPS Energy's Save for Tomorrow Program (STEP) was approved in 2009 with the objective of reducing energy consumption by 771 MW over 10 years by incentivizing customers to save energy through the adoption of energy efficiency technologies and behavior changes. By the end of 2021, CPS Energy had reduced energy consumption by 926 MW with a cumulative investment of $775 million. Under STEP, demand response programs include (1) residential weatherization; (2) residential and commercial energy efficiency; (3) commercial and industrial demand response; (4) incentives for installation of residential and commercial rooftop solar panels; (5) incentives for installation of commercial electric charging stations; and (6) time-of-use tariff rates.

The positive impact of the energy efficiency and demand response programs under STEP is significant. During the 2020 Summer, customer responses to energy alerts resulted in reductions in power demand of 273 MW off peak and 231 MW at peak. In 2019 alone, these programs resulted in 198 GWh in energy efficiency and 242 MW in peak demand savings.

One aspect of STEP introduced financial incentives for residential and commercial retail customers to invest in rooftop solar panel systems. The cumulative investment in customer incentives for over a decade has resulted in 355 MW of DER solar energy capacity currently installed within the jurisdiction boundaries of the City of San Antonio.[9]

Transmission and Distribution Modification

Q: What equipment, processes, and standards need to be implemented to allow for further DER participation?

Further DER participation in the ERCOT wholesale market will require the integration of DERs into a smart grid to enable the dispatchability of DERs as necessary to offer demand response or ancillary services to help balance the transmission grid. That means that distribution operators will need the necessary tools to plan for the integration of DERs to meet distribution system objectives, such as energy reductions in system non-coincident peak and on-peak, or to facilitate the dispatch of DERs to provide wholesale transmission services. Distribution operators will need visibility over DERs, situational awareness of distribution facilities that could be affected by DER dispatch, ability to curtail DERs, real-time communications with DERs and ERCOT, and tariff rates to enable cost recovery for the use of the distribution system to transport DER energy to the transmission grid.

An item requiring attention will be the interaction between DERs providing ancillary services and the possibility of them being located on a load-shed circuit. We would caution against a blanket designation of such facilities being recognized as critical infrastructure. The more DERs that are protected from outages in this way will reduce load shed capacity available to the grid.

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[9] *Shining Cities 2022: The Top U.S. Cities for Solar Energy*, Environmental America Research & Policy Center and Frontier Group, April 2022, report authored by Adrian Pforzheimer & Johanna Neumann. Based on data collected by the researchers for end of 2021, CPS Energy ranks 5th among U.S. cities with the most distributed solar energy capacity with 354.9 MW and 6th in solar PV watts per capita with 247.4 watts per person. Report available at: https://environmentamericacenter.org/sites/environment/files/Shining_Cities-2022.pdf.

Additionally, DER outages may also be a concern. As DER equipment becomes unavailable, on either a planned or unplanned basis, it may impact the distribution equipment with which it is interconnected. Lack of coordinated outages could lead to system instability. Equipment capable of more granular outage management will be necessary to address this issue. Similarly, there should be clear rules on the responsibility of resource entities that own or control DERs regarding the replacement of power or ancillary services offered by a DER that is unable to meet a contractual obligation.

Finally, the aggregation of DERs will require new tariffs that ensure that the resource entities controlling DERs are properly compensating distribution system owners for the use of their infrastructure to access the transmission grid.

Within the service territories of non-opt-in entities (NOIE), such as municipally owned utilities (MOUs), DER participation in the wholesale market would have to be coordinated through the MOU to ensure the resource entity controlling the DER is not engaged in the illegal sale of retail electricity within the NOIE service area, among other items. The QSE representing the DER or ALR could be the MOU itself, or a third-party QSE. CPS Energy already addressed this issue during the development of a resiliency tariff service for commercial customers. CPS Energy's resiliency service entails an arrangement with a third-party that installs a gas fuel back-up generator at the customer site. Whenever the customer experiences a temporary outage, CPS Energy provides the resiliency service with power purchased from the third-party. At other times, the third-party is able to provide ancillary services to the wholesale market, while ensuring proper cost recovery to CPS Energy for the use of its distribution system.

Turning to equipment necessary for the integration of DERs, the distribution system will require the facilities to interconnect with DERs, advance meter infrastructure (AMI), upgrades in SCADA systems, voltage-regulation equipment, step-up transformers, two-way circuitry design, telemetry equipment, and two-way communications equipment with the DER. CPS Energy has already made a substantial investment to deploy AMI meters throughout its service area. In addition to the hundreds of thousands of electric and gas smart meters, this deployment involved the installation of over 1,300 networked devices to establish a wireless communications network as the platform to collect smart meter data and over 1,100 distribution automation devices. The AMI deployment affected over 462 discrete business operations and processes throughout the organization resulting in the need for significant personnel training and change management decisions. Beyond smart meters, the amount of power that can flow back to the grid is limited based on the size of our transformers, which is accounted for in the interconnection process. Transformer upgrades would be required to allow additional capacity to be injected into the distribution grid over existing limitations.

Turning to technical standards that could be adopted to promote the integration of DERs, it is important to recognize that the current electric power system is not well positioned to handle a high penetration of DERs on the distribution system, as that system was mainly designed to deliver power from the transmission system to distribution load. Increasing the amount of interconnected DERs into the distribution system creates various technical challenges, including system protection, power quality, response to bulk power system disturbances, and voltage and frequency regulation.[10]

The key to addressing some of these challenges in an environment of high DER penetration is DER equipment with smart inverter technology that can detect information about the grid at its location, such as voltage and frequency, and respond autonomously in ways that help maintain grid stability. In April 2018, the Institute of Electrical and Electronics Engineers (IEEE) published the "base standard" IEEE Standard 1547-2018, which established sweeping changes to the technical rules of interconnection for DERs, compared to the previous version from 2003, particularly in relation to smart inverters. However, the test procedures for compliance with the new capabilities needed major revision before any equipment could be certified under the new standard. On May 21, 2020, IEEE Standard 1547.1-2020 was released establishing these testing procedures. According to the release, the timeline to have tested and certified compliant DER equipment available on the market is 2021-22.[11]

At CPS Energy, the process for DER interconnection is governed by interconnection standards outlined in the DG Manual. We support efforts to identify best practices and sharing these practices with others in industry forums. As technology evolves and new DER equipment matures, focus has shifted to equipment requirements that support distribution system reliability, as evident by the IEEE 1547-2018 and 1547.1-2020 standards. We support these standards.

Cost Quantification

Q: How much transmission and distribution investment will be necessary and what methods would be available to recuperate costs?

As a starting point for this discussion, the Commission should define DER related terms in relation to different types and sizes, including the aggregation of DERs. The next step is to identify a technical framework to achieve the desired policy goals for DERs. Only after these two foundational concepts are formulated can an assessment of necessary investment to recover costs be developed.

Another important consideration is that recovery of distribution system investment made in support of DERs, especially for the aggregation of DERs within a NOIE's service territory, will be subject to regulatory bodies other than the Commission. Allowing for any distribution investment cost recovery outside of the established ratemaking methodologies will need careful consideration to preserve jurisdictional boundaries and cannot be accomplished outside of a change in law.

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[10] *Why Do We Need Standards Like IEEE 1547*, IEEE Smart Grid, Oct. 2016 by Babak Enayati. Article available at: https://smartgrid.ieee.org/bulletins/october-2016/why-do-we-need-standards-like-ieee-1547.

[11] *The Long-Awaited IEEE Standard for More Energy Storage on a Smarter Grid*, Energy Storage News, Aug. 10, 2020 by Brian Ludic. In 2018, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution recommending that states adopt the current IEEE 1547 standard and align implementation of the standard with the availability of certified equipment. Article available at: https://www.energy-storage.news/the-long-awaited-ieee-standard-that-paves-the-way-for-more-energy-storage-on-a-smarter-grid/.

Q: And should we consider new methods of cost allocation and recovery for DER-related infrastructure enhancements?

Any allocation methodology for recovery of a MOU's distribution infrastructure expenses undertaken to integrate DERs that spreads costs to customers outside the MOU, such as the transmission cost of service rate method, will find conflict in PURA.[12] We encourage an open deliberation on the issue but do not support a new methodology to allow for cost recovery outside of the current statutory framework.

Data Accessibility

Q: 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?

Untapped DER potential is currently focused on rooftop solar energy capacity resulting in a desire for inputs into forecasting models. Typically, these inputs include customer level data which will require a high level of privacy protection. We expect that outside vendors providing forecasting services will rely on distribution utilities to provide data to produce and improve forecasts. New data sources will also be required for DERs. Some utilities may not have or be able to use premise level data in planning models. There is also a risk of including the DER information into models to measure resource adequacy. In short, planning and resource adequacy goals may not align.

Currently, ERCOT Critical Infrastructure Security Department utilizes industry best practices and the NIST Cybersecurity Framework to guide and shape its policies and programs. We support the continued use of this framework and best practices. The NIST Cybersecurity Framework outlines security controls under the "Protect" function and "Data Security" subcategory (PR.DS). These controls must be effectively implemented meeting the latest standards outlined in the NIST SP800-53 and supporting FIPS requirements.

Q: Additionally: What classes of DERs ought to be considered?

We support a policy where DERs are ranked based on their respective impact to reliability (primarily) and market efficiencies (secondarily). Since DERs can range widely in their characteristics, creating a classification system would allow developers and utilities to create a common understanding of the reliability benefits and integration challenges associated with each class. We support focusing on classes that provide the most reliability benefit with the least cost to implement. This includes larger DER projects and potentially DER aggregations. These classifications should be considered in developing a new definition of DERs.

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[12] Except for certain exemptions not relevant to this discussion, under PURA Section 32.002, the Commission does not have authority "to regulate or supervise a rate or service of a municipally owned utility." That authority lies with the municipality's governing body that created the MOU and issues securities to support its operations pursuant to Texas Government Code, Chapter 1502. Under Section 1502.057, the MOU's rates must be equal and uniform and sufficient to pay all expenses associated with providing utility service and repayment of outstanding securities.

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

The most significant step that the Commission can take to create consistency in interconnection agreements is to require DER equipment to be certified in compliance with the IEEE 1547-2018 and IEEE 1547.1-2020 standards. Beyond this point, there should be flexibility to account for the great diversity in nearly every aspect of the distribution system across utilities. Distribution systems are operated at various voltage levels across service territories subject to different geographic conditions within the ERCOT region and using varying staffing and engineering strategies. This is all underpinned by the varying cost-of-service rates of the different utilities.

Q: What can reasonably and economically be done within a 5-year timeframe?

The Commission should require that all DERs interconnected at the distribution level comply with IEEE 1547-2018 and 1547.1-2020 standards within this time frame. Additionally, DER definitions and the technical framework to support them could be developed in a 5-year timeframe. The Commission could also encourage the modernization of distribution systems that integrate DERs by approving rate requests of distribution systems within its jurisdiction and encourage NOIE regulatory bodies to do the same. Only then will implementation of smart grid applications and technologies begin. Consider that a control system upgrade typically takes three years from design to system commissioning, but it can only be designed, tested, and deployed once the design parameters are established.

Respectfully submitted,

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ATTORNEYS FOR CPS ENERGY

PUC PROJECT NO. 51603

REVIEW OF DISTRIBUTED ENERGY RESOURCES	§ § § § §	**BEFORE THE PUBLIC UTILITYCOMMISSION OF TEXAS**

EXECUTIVE SUMMARY OF CPS ENERGY

The Commission should develop new definitions classifying DERs based on their reliability and market efficiency benefits. This should be followed by the development of a technical framework that addresses necessary upgrades to integrate such DERs as part of an intelligent grid. Only after these two steps are completed can an estimation of costs to integrated DERs be realized. In this respect, the Commission should approve rate requests from distribution utilities within its jurisdiction to support grid modernization and encourage NOIE regulatory bodies to do the same.

Over the last 20 years, CPS Energy's regulatory body has made substantial investments in grid modernization and energy conservation programs that have incentivized growth in DER capabilities. These investments have included incentives to retail customers to adopt rooftop solar systems that today account for 355 MW of DER energy capacity within the City of San Antonio. CPS Energy has also invested in renewable energy, which accounts for 22% of its total generation capacity, including 100 MW of solar resources connected at the distribution level, as well as 20 MW of energy storage.

CPS Energy's example demonstrates that the implementation of DERs is a long-term investment that is part of the distribution system's grid modernization. The Commission should recognize from this example that distribution system operators will need to have the necessary technology tools to allow them to have visibility into DERs and the ability to safely deploy their energy capabilities to support the distribution system's demand response objectives or the provision of ancillary services into the transmission grid. By necessity, this will require system operators to have the ability to curtail DERs if they pose a threat to the reliability of the distribution system, and the same will be true for ERCOT in relation to the transmission grid.

In the short-term, the Commission should require that all DER equipment interconnected at the distribution level be compliant with the IEEE 1547-2018 and 1547.1-2020 standards supporting smart inverters. In the long-term, the Commission should promote grid modernization and cost recovery methodologies that respect the jurisdictional boundaries of NOIE regulatory bodies.