Received - 2022-06-15 11:58:32 AM
Control Number - 51603
ItemNumber - 26
INITIAL COMMENTS OF AUSTIN ENERGY

Austin Energy\(^1\) files these comments in response to the Public Utility Commission Staff’s request for comments issued in this Project on April 29, 2022. Formed in 1895, Austin Energy is a municipally-owned utility (MOU) that serves over 500,000 customers in the greater Austin region. Austin Energy provides all functions of electric service to its customers, including generation, transmission, distribution, and customer service. Austin Energy manages a diverse generation resource portfolio with more than 5,000 MW of capacity comprised of natural gas, nuclear, coal, biomass, wind, and solar resources that fully participates in the competitive ERCOT wholesale electricity market. Austin Energy appreciates the opportunity to offer its perspective on distributed energy resources (DERs).

**Introduction**

Austin Energy recognizes the potential of DERs to empower customers, reduce costs and emissions, and when integrated systemically, improve the reliability and resiliency of the grid. Due to the complexity, costs, and potential safety issues associated with DER integration, a phased and measured approach to adoption is important and should be guided by a cohesive market design with clear price signals. As technologies and customer demands have evolved in recent years, Austin Energy has worked to provide a variety of incentives and services to encourage adoption of DERs. Austin Energy is a customer-facing MOU that owns and operates its own distribution system, providing it with flexibility in integrating DERs and deploying innovative DER projects. Austin Energy responds to these questions based on its experience with a variety of DER technologies and approaches with the hope that our experiences are helpful in further advancing the goals of this project. However, Austin Energy notes that the legal and regulatory framework under the Public Utility Regulatory Act (PURA) provides MOUs, rather than the Commission, jurisdictional authority over MOU distribution systems. Austin Energy echoes the comments submitted by the Texas Public Power Association (TPPA), urging the Commission not to pursue

\(^1\) City of Austin d/b/a Austin Energy
uniform, prescriptive standards that would compromise the ability of MOUs to engage in local, customer-driven innovation. Austin Energy believes that the results of MOU projects can provide the Commission and other market participants with valuable real-world data on the merits of different programmatic structures.

Responses to Specific Questions

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

Austin Energy agrees that planning and control are key challenges in integrating DERs while maintaining a reliable, affordable, and safe distribution system. Holistic integration of DERs is a large, multifaceted project that will require the Commission to first solicit expertise and input from a wide array of stakeholders including customers, vendors, advocacy groups, researchers, and policymakers. Each technology type will have unique market and grid impacts, interconnection standards, and customer adoption/use case profiles. Without continuous stakeholder engagement, utilities and regulators will be working behind the technological curve as customers adopt new systems such as vehicle-to-grid charging and solar-integrated storage. This could result in dollars and resources invested to incorporate technologies that are no longer desired by customers by the time project completion is reached.

Austin Energy is currently experiencing high levels of public and commercial interest in many types of DER technologies and is continually reevaluating its processes and working with customers to create meaningful solutions that appropriately meet customer demands. Given the unique and evolving challenges with each technology, Austin Energy believes that its ability to quickly respond to customer demands is critical, especially while many DER technologies are still in their infancy. Major events can change customer demands, demonstrated by the accelerated interest and integration of DERs after Winter Storm Uri. Accordingly, a premature one-size-fits-all approach to planning and control processes could complicate ongoing efforts at Austin Energy and other MOUs as goals and objectives vary based on local customer needs.

i. What are the different utilization and participation formats for existing DERs on distribution networks?
Formats vary greatly based on ownership model, location, and functionality of the DER technology. DER formats utilized by Austin Energy include load reduction (e.g. smart thermostats), generation (e.g. solar), and two-way flow assets that can be used as a generating asset but have the load profile of a customer (e.g. energy storage, EVs). Customer participation is primarily managed through Austin Energy via programs that have a direct community benefit to the utility, which is then translated to the customer. Examples include Value of Solar\(^2\) metering and incentives for the installation of thermostats and water heaters capable of demand response.

Additionally, Austin Energy is developing a new Reliability-as-a-Service (RaaS) program that will allow Austin Energy to act as Qualified Scheduling Entity for DERs located at a variety of commercial and residential loads. This program is built for local needs and will provide resiliency for critical loads at reduced cost while providing Austin Energy with hundreds of megawatts of additional generation resources that can be dispatched based on wholesale market signals.

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

Austin Energy assumes the Commission is referring to increasing the size limit on unregistered DERs, which would likely facilitate faster and expanded DER penetration as registration requirements significantly increase project costs due to the need to comply with ERCOT requirements, install meter telemetry, pay impact study fees, etc. This could allow more utilities to benefit from the market impacts of DERs and would provide additional data to quantify the distribution system impact of increased DER penetration. However, a higher size limit would also significantly increase workloads and safety concerns for utility planners, who must evaluate applications and often work within tight time and budgetary constraints. Additionally, higher penetration of larger unregistered DER systems could lead to contrary outcomes by compromising the reliability of the distribution system in a manner that impacts services to other customers. Any size limitation increase should therefore be studied carefully.

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\(^2\) Austin Energy’s Value of Solar rate credits customer bills who own onsite photovoltaic systems for every kilowatt-hour of electricity that system generates. The current Value of Solar rate, which is under review, is 9.7 cents per kWh (effective January 1, 2018).
2. **Transmission and distribution modification:** What equipment, processes, and standards need to be implemented to allow for further DER participation?

**Data Synchronization & Performance Measures for DER:** Further DER participation will require real-time telemetry and consistent data streams to provide the situational awareness necessary to balance supply with demand and maintain an accurate understanding of power system conditions to make timely decisions and direct market resources as needed to maintain reliability, market response, and comply with ERCOT regulations such as NPRR1077. System modeling should incorporate DERs and operators must know DER volumes, capabilities, performance, and locations.

**Technical Standards & Interoperability:** A set of Reliability Protocols and Operating Guidelines need to be established to provide accurate modeling data, key practices, system design, configuration, operational criteria (voltage, frequency, etc.), and maintenance guidance to accommodate the integration of DERs. Any potential interaction of these new guidelines with already established requirements need to be fully evaluated and identified to ensure that they are compatible. Sufficient information to support DER generation forecasting and the impact of system load including dispatch scenarios need to be considered and established.

**Inverter Standards and Capabilities:** Inverters remain a major area of concern, and better inverter standards and enhanced inverter capabilities will be necessary to manage power quality on the distribution network. Eventually, when better communications and telemetry are established, enhanced inverter capabilities will assist DER participation to fully integrate in energy markets.

**Interconnection & Safety Standards:** The ERCOT interconnection process should include assessments of the impact of DERs on the transmission and distribution systems for resources within a given threshold. This would not require ERCOT to perform distribution planning/operations studies — instead, the affected Transmission and Distribution Service

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3 See NPRR1077, **Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs.** In order to ensure that SOGs in Self-Limiting Facilities abide by established MW Injection and MW Withdrawal limits, and in order to ensure that ERCOT operators and system planners have clear visibility into the performance of SOGs, this NPRR requires the Qualified Scheduling Entity (QSE) for any SOG to provide telemetry of the injection or withdrawal at the Point of Interconnection (POI) (for transmission-connected sites) or Point of Common Coupling (POCC) (for distribution-connected sites) as well as telemetry of gross real power injection and withdrawal at the generator terminals and the status of each SOG’s breaker. Self-Limiting Facilities that include SOGs would be subject to the same consequences as other Self-Limiting Facilities when the MW Injection or MW Withdrawal limit is exceeded.
Provider should perform the impact analysis on their transmission and distribution system utilizing the NERC/ERCOT recommended processes. NERC has published a report on DER connection modeling and reliability that should be considered in any relevant rulemaking.

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?

DERs will necessitate improvements to the transmission and distribution system that will impose significant costs, including the installation of dedicated distribution feeders, reconductoring, installation of equipment to mitigate voltage issues, the addition of capacitor banks to maintain the power factor, and system protection upgrades. Infrastructure needs of specific projects and their costs are determined through DER impact studies, and will vary based on the size, function, and location of the DER. As with generation interconnection to the transmission system, the interconnection costs for DERs to the distribution system should be carried by the resource based on cost-causation principles. Customers realize benefits — lower bills, resiliency, etc. — from DERs and thus should shoulder these costs in most circumstances as to avoid placing burdens on other customers. The utility should not be obligated to cover these costs without recovery.

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

Austin Energy undertook the Sustainable and Holistic Integration of Energy Storage and Solar Photovoltaics (SHINES) project to optimize the value stream for solar and storage within our service territory. The project identified use cases for solar and storage DERs, including market signals such as energy arbitrage in the real-time and day-ahead energy markets and provision of ancillary services. Sizing DERs for market participation use cases requires a cost/benefit analysis that balances greater revenues achievable through larger DER size with capital, operating, and degradation costs. Local market participation requirements and coordination strategy between market use cases must also be considered. Engagement with an organization’s market operations

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group is helpful in achieving correct sizing for market use cases. Other grid services to be considered for DERs include:

- **Demand Charge Reduction (DCR):** Storage DERs can reduce a demand charge on a customer’s bill by releasing energy during times when the customer’s demand is peaking and recharging during low demand periods. Enabling this functionality requires both historical and predictive analytics, with a DER installation behind-the-customer meter.

- **Day-Ahead Energy Arbitrage (EA):** The ability of storage DERs to be discharged during high prices and charged during low prices can be translated into value through the Day-Ahead Market (DAM) in two ways. The first involves making a commitment to buy/sell energy a day in advance based on real-time market price predictions being higher/lower than the day-ahead prices. The second provides a target day-ahead schedule based on the prices but can be adjusted in real-time.

- **Real-Time Price Dispatch (RTPD):** Real-Time Price Dispatch takes advantage of volatility in real-time energy prices — similar to energy arbitrage but on time scales as short as five minutes. Typically, price spikes only last a short (5 to 15-minute) interval, so short-term prediction and fast response is imperative. Energy storage, being bi-directional, can strategically take advantage of both spikes and troughs in prices.

- **Distribution Voltage Support (VS):** Voltage support brings reliability value to the distribution utility and seeks to maintain the voltage of a distribution circuit within the ANSI C84.1 limits of 0.95 and 1.05, offsetting any volatility that may occur. Solar PV systems on the distribution system, particularly at higher penetrations, are a primary cause of voltage volatility due to their intermittent power generation and rapid ramp rates.

- **Congestion Management (CM):** Congestion events in power systems occur when electricity flow across a system component exceeds its safe design capacity limitations. The goal of congestion management is to use the active power capability of DERs on a circuit to relieve congestion problems in the circuit, helping Distribution Service Providers (DSPs) mitigate load shedding events, increasing life of assets, and increasing renewable energy hosting capacity of distribution circuits.

- **Peak Load Reduction (PLR):** The addition of distributed solar generation or discharge of stored energy from batteries can reduce peak load during potential 4CP days, leading to
significant savings for DSPs in the ERCOT market via reduced transmission costs as well as reducing stress to the transmission system during peak load.

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?

Some utilities offer tools for the customer to see interconnection limitations along each feeder. This could potentially allow for more targeted deployment of DERs but must be done carefully to preserve customer privacy as well as sensitive information about critical infrastructure.

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

   Austin Energy has no comment at this time.

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)

   DER types should be classified based on type (EV, energy storage, device, solar, etc.), location (behind vs. in front of the meter, distribution vs. transmission system), and ownership model (customer or utility owned). Additionally, grid following (current source) vs. grid forming (voltage source) should be captured — this accounts for the ability of the DER to create an island.

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

   Segmentation and islanding are a major safety concern and needs to be evaluated closely. Islanded systems deprive the grid of reliability services (voltage support, congestion management) as well as benefits from market participation (such as 4CP reduction). Individual interconnection agreements can cover circumstances such as storms but are very hard to enforce. Using a DER to form an island to back-feed part of the grid could be extremely dangerous for line crews working on energized lines. Sources for ground faults and overrides of existing anti-islanding protective
equipment are additional concerns. With respect to segmentation with DER islands, Austin Energy would require substantial system upgrades to accommodate this from a system protection and crew safety standpoint.

Critical facilities that are registered and accounted for should be able to island themselves if the correct equipment is installed. Austin Energy recently received a grant from the Department of Energy and is working with the Electric Power Research Institute to design and develop a novel distributed solar photovoltaic microgrid system (Solar Critical Infrastructure Energization, or SOLACE) with storage and enhanced grid control capabilities. The overall goal of the system is to act as a backup source of electricity for critical infrastructure in event of a grid failure and is focused on developing several system capabilities including flexible energy pathways, distributed management systems, solar/storage inverter integration, advanced load control, and advanced cyber-security features. These capabilities would be integrated into the SOLACE platform and modelled using an existing electrical pathway between an existing battery energy storage system and an emergency communications center. Residential homes in the area would also be studied to analyze additional loads as well as local generation that could be incorporated to the designated pathway. This modelling exercise could lead to a field demonstration as part of a future phase.

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

Austin Energy has no comment at this time.

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

Austin Energy has no comment at this time.

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

Austin Energy has no comment at this time.

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

Austin Energy has no comment at this time.

vii. What other issues, if any, should the Commission consider and address while developing rules related to DERs?
Rules that apply DER-wide will likely be difficult to establish due to the varying use cases and functionality as highlighted above. Subject matter expertise and real-world experience safely implementing these technologies are necessary for each DER type as well as grid impacts such as market operations, grid support, customer adoption, and programming expertise. The Commission should refrain from adopting a one-size-fits-all approach to DERs with mandatory rules, particularly for MOUs.

**Conclusion**

Austin Energy appreciates the opportunity to submit these comments and looks forward to working with the Commission and other parties on safe, affordable, and reliable DER integration.

Dated: June 15, 2022

Respectfully submitted,

**CITY OF AUSTIN D/B/A AUSTIN ENERGY**

By: /s/Tammy Cooper

Tammy Cooper
Senior Vice President, Regulatory, Communications and Compliance
Telephone: (512) 505-3901
Email: tammy.cooper@austinenergy.com
EXECUTIVE SUMMARY
INITIAL COMMENTS OF AUSTIN ENERGY

General Comments

- Due to the complexity, costs, and potential safety issues associated with DER integration, a phased and measured approach to adoption is important.
- Full integration of DERs will require stakeholders to resolve a wide array of regulatory complexities from a holistic perspective guided by a cohesive market design with clear price signals. This will include the need for real-time telemetry, technical standards that ensure interoperability, cost allocation, standards for inverters, and standards for interconnection and safety.
- DERs will necessitate improvements to the transmission and distribution system that will impose significant costs, including the installation of dedicated distribution feeders, reconductoring, installation of equipment to mitigate voltage issues, the addition of capacitor banks, and system protection upgrades. Segmentation and islanding of systems pose significant reliability and safety concerns. Cost-allocation should generally be conducted using cost-causation principles. Utilities should not be obligated to cover these costs without recovery.
- DERs can offer utilities valuable grid services by reducing demand charges, arbitraging the day-ahead and real-time energy markets, providing distribution-level voltage support, managing congestion, reducing peak load, and providing resiliency to critical facilities during grid failure events.

Role of Municipally Owned Utilities

- Austin Energy recognizes DERs’ potential to empower consumers, reduce costs and emissions, and improve the reliability and resiliency of the grid. Austin Energy has taken or is currently taking several actions to facilitate and encourage DER adoption, including:
  - Offering “Value of Solar” credits to customers with rooftop solar.
  - Upgrading billing systems and distribution infrastructure to accommodate DERs safely and reliably.
  - Offering incentives for the purchase and inclusion of smart appliances in Austin Energy’s demand response programs.
  - Working on our forthcoming Resiliency-as-a-Service (RaaS) program, in which Austin Energy will act as QSE for large customer-sited distributed generation.
  - Participating in demonstration and research projects such as SHINES and SOLACE.
- As customer-facing entities operating their own distribution systems, MOUs have additional flexibility to deploy new distribution-system products. MOUs evaluate DERs based on community priorities and align adoption and deployment accordingly.
- The current legal and regulatory framework provides MOUs with oversight of their own distribution systems. At this time, uniform and prescriptive standards for DERs would hinder adoption in MOU service territories and are not needed.