Filing Receipt

Filing Date - 2024-09-30 02:49:47 PM

Control Number - 54224

Item Number - 49

PROJECT NO. 54233
PROJECT NO. 54224

COST RECOVERY	**§**	**BEFORE THE**
FOR SERVICE TO DISTRIBUTED	**§**	**PUBLIC UTILITY COMMISSION**
ENERGY RESOURCES	**§**	**OF TEXAS**

BASE POWER COMPANY'S COMMENTS IN RESPONSE TO STAFF'S QUESTIONS

Base Power appreciates the opportunity to provide input to the Commission's discussion and is thankful for staff's diligence in working to remove barriers to further DER implementation. Base Power is a Texas residential energy storage developer, installer, and Retail Electricity Provider (REP) with a unique business model: Base owns and operates batteries deployed behind-the-meter on the homes of its retail energy customers. Base has therefore launched as a new type of full service energy and storage provider for residential customers in Texas. Base is committed to strengthening the grid and bringing further resilience to customers through its assets.

Q1. Can the Commission implement the proposed standard distribution resource interconnection allowance without explicit statutory language authorizing such an allowance?

The Commission is not prohibited from implementing a standard distribution resource interconnection allowance under the broad powers granted by the Public Utility Regulatory Authority Act (PURA). Specifically, PURA §14.001 provides the Commission with general authority over interconnection, transmission, and distribution of electric service. Moreover, PURA § 36.003 grants the Commission the power to ensure that utilities provide service in a manner that is non-discriminatory and cost-effective, which could include establishing rules or allowances that encourage DER deployment by mitigating the cost of interconnection.

Furthermore, the Distribution Cost Recovery Factor (DCRF), outlined in PURA §36.210, allows DSPs to recover costs associated with distribution system improvements. The DCRF can be a useful tool for socializing the cost of interconnection upgrades, particularly in a way that ensures that DER-related upgrades are recoverable without placing undue financial burden on individual customers or DER providers.

While explicit statutory language authorizing an interconnection allowance may not exist for distribution-level resources, the Commission's broad regulatory powers under PURA provide a strong foundation for such an allowance, especially since explicit language prohibiting such action is absent.

Q2. What are the advantages and disadvantages of the proposed standard distribution resource interconnection allowance? Is a standard distribution resource interconnection allowance a viable option to move forward? If not, why?

Establishing an interconnection allowance offers a more equitable distribution of cost for system upgrades and will lead to further implementation of DERs, resulting in cost-effective and enhanced resilience of the grid. The current system unfairly burdens the most recent resource or consumer who chooses to increase the system and their own reliability with backup power, by levying the full charge of system upgrades against them. The proposed interconnection allowance could be a possible solution to this inequity. By granting access to the allowance to residential DERs, the Commission can help ensure that consumers are better equipped to withstand outage events. Without access to such an allowance, DER providers are less incentivized to deploy assets in areas where the system equipment cannot sustain additional capacity because installation would trigger an uneconomic outcome for the customer or the provider itself. Often, neighborhoods in lower income areas with older infrastructure require these costly upgrades.

Furthermore, access to the allowance will lead to more strategic implementation of DERs. This is a beneficial outcome to the entire system. Aside from the benefit of daily resilience and long-term outage protection, installation of DERs will be more directly tied to increasing needs for reducing peak demand and accessing dispatchable resources to serve those peaks. Implementing the allowance for smaller DERs may also reduce the urgent need for dynamic hosting capacity maps, as Base requested the ADER Task Force to evaluate in Project no. 53911. Adopting the allowance approach alleviates, specifically, the concern that a single marginal customer or developer will be impacted by outsized upgrade costs to which there is no visibility today due to the lack of hosting capacity information.

Q3. At what amount should a standard distribution resource interconnection allowance be set? Should the applicability or amount of the allowance vary based on the size of the resource?

Base suggests a tiered approach to the interconnection allowance amount and supports comments filed by GRIT on this topic in this proceeding. Base also supports a delineation of sizes for the allowance approach as follows: less than 10 kW, between 10 kW and 500 kW, between 500 kW and 2 MW, and over 2 MW.

Upfront interconnection costs for non-residential DERs are significantly higher than the interconnection costs for residential DERs. Post-installation costs for residential applications can rise to about $10,000[1] due to necessary upgrades of local distribution system transformers, which arise on an ad hoc basis without prior knowledge to the customer or installer on cost estimates. In

[1] *See* https://www.larsonelectronics.com/product/150231/100-kva-overhead-distribution-transformer-pole-mount-4160grdy-2400-grounded-wye-pri-120-240y-sec-mineral-oil-aluminum-onan for transformer pricing

other words, when a new DER is added to a residence and connected to the grid, any required upgrades to the local distribution infrastructure - such as transformer upgrades - are typically charged to the customer or installer associated with that specific installation. This approach overly burdens individual consumers and disincentivizes broader deployment of DER technologies (and skews the benefits of the additional resiliency that is being added to the system towards existing customers, who may or may not already have installed similar assets). The marginal customer on a distribution circuit should be motivated to install more resiliency that is dispatchable, supports loading constraints on local transformers, enhances power flow, power flow modeling for the distribution operator, and helps the distribution operator anticipate demand constraints on the same circuit. Current policy has the distorted effect of penalizing customers who spend their own capital to add this benefit to the system instead of rewarding them.

As for the amount of the allowance, we would recommend the PUCT undertake a similar deliberative process in calculating the distribution allowance as they did for the transmission allowance earlier this year[2], applying statistical methods and analyzing historical data to identify costs.

Q4. How should the interconnection costs covered by such an allowance be reallocated? What effects would this have on other customers?

We propose that the costs for smaller DERs covered by the interconnection allowance be incorporated into the DSP DCRF filings at the Commission. By using the DCRF process, the costs associated with DER interconnections, particularly for necessary upgrades, can be equitably distributed across all of the DSP's customers.

This approach has multiple benefits:

1. **Cost Sharing**: Rather than imposing the full cost of infrastructure upgrades on individual consumers or DER providers, these costs would be shared among the entire customer base. This minimizes the financial burden on those adopting DER technology while also ensuring that necessary system upgrades are made to maintain grid reliability. This cost-sharing approach is aligned with the shared benefits all customers enjoy as a result of greater grid resiliency.
2. **Minimal Impact on Monthly Bills**: Because DCRF filings typically involve spreading costs over a large customer base, the incremental increase in customer bills would be extremely small. The shared cost mechanism ensures that the overall impact on customers' monthly bills is kept low, making it a more palatable solution for the broader public. A rough high level impact analysis to customers is below.
    a.

[2] See *Generation Interconnection Allowance*, https://interchange.puc.texas.gov/Search/Filings?ControlNumber=55566

Item	Value	Source/Assumption
Expected DER growth 2025-2034	300,000	TXSES, assumes doubling in 10 years
% requiring system upgrade in next 10 years	10%	Avg existing transformer size = 37.5kVA, Avg # customers/transformer = 3, Avg system size = 10kVA
Distribution customers	27,000,000	ERCOT
Average upgrade cost	$10,000	See above, 100kVA transformer install
Per customer impact over 10 years	$11.11	Calculated value
Per customer impact per year	$1.11	Calculated value

3. **Rate Case-Integrated Value Creation from DERs for Grid Reliability and Resilience**: Integrating cost allocation via allowances in DCRF proceedings with benefits to ratepayer classes and distribution system resilience creates a viable path for just and reasonable rates for utility customers. DERs should be valued as a distribution grid resiliency tool and cannot be viewed as such without being part of the same bucket of investments and activities which motivate electric utilities to invest ratepayer funds in upgrades to better serve customers (more affordably and reliably.) Distribution system peak demand mitigation is a primary, socialized benefit of individual DER adoption metrics which should be valued in the same proceeding in which DER costs are being allocated to one or more customer classes. Integrating costs within DCRF filings also promotes a more transparent process to evaluate the ongoing deployment and impacts of DERs on the grid while giving other stakeholders line-of-sight and the ability to provide input.

Q7. What disparities exist between distributed generation and energy storage resources interconnecting at transmission and distribution voltages?

Both DERs and energy resources connected at transmission voltage are crucial to improving grid resiliency. However, DERs connected at distribution voltage offer additional advantages, particularly direct impact to peak distribution system demand and localized reliability benefits. Residential DERs, for instance, can operate independently of the distribution system during outages, providing vital backup power during system failures or severe weather events. This specific and localized placement of DERs also reduces strain on the system in specific locations

as determined by the grid operator by offsetting the load of a home during times of peak demand.

Additionally, the lack of standardization in interconnection agreements and technical requirements for DERs can exacerbate the disparities between transmission and distribution-level connections. The Commission could address these disparities by prioritizing the standardization of interconnection agreements, processes, and technical requirements for residential DERs, ensuring a more streamlined and equitable approach to resource integration across voltage levels. Standard processes across and among DSPs would incrementally lower overall costs not only for DER providers, but most importantly, for residential customers. Furthermore, aligning residential interconnection requirements with those of the TDLR-adopted National Electric Code (NFPA 70) would further simplify code compliance and promote the adoption of DERs. This would provide further clarity and ease the deployment of residential DERs, thereby accelerating the overall adoption of DER technologies.

Q8. What, if any, action should the Commission take to address these disparities in a uniform fashion?

Base suggests the Commission take the following actions in response to this project:

- Implement a tiered interconnection allowance based on project size.
- Allow Distribution Service Providers to recover costs through the DCRF process and also allow in the same rate case proceedings to ascertain, define, and value benefits of increasing DER penetration on distribution systems (including emergency stress mitigation before and after major storms, capital investment deferral, climate adaptation risk management, and resiliency and rotating outage management strategies).
- Prioritize the standardization of interconnection agreements, distribution interconnection processes, and technical requirements. For residential DERs. Specifically, several stakeholders including Base have provided comments in Project No. 54233[3] indicating the urgent need to streamline residential DER storage and solar interconnection processes and requirements.
- Disconnect Project 54233, *Technical Requirements for Distribution Interconnection*, from Project 54224, and address in 1Q2025 these technical issues apart from the allowance associated topics. By providing a separate platform to address technical interconnection issues, the Commission as well as stakeholders, can be more deliberate, granular, and clear about what technical and operational issues should be evaluated and modified.

---

[3]*See Base Power Comments on Residential (< 1MW) DER Interconnection Standards,* https://interchange.puc.texas.gov/Documents/54233_85_1397563.PDF, recommending the implementation of a streamlined residential interconnection program to encourage distributed energy resource (DER) adoption in Texas. Key elements include introducing dynamic export limits to prevent unnecessary upgrades, creating live hosting capacity maps for better decision-making, streamlining interconnection processes through automation, and promoting the use of Meter Socket Adaptors (MSAs) for cost-effective and safe DER deployment.

Executive Summary

The following is a summary of a proposed solution and process to implementing the proposed interconnection allowance and standardizing interconnection of DERs.

1. **Scope of interconnection allowance.** Base believes adopting a distribution level interconnection allowance is well within the Commission's broad powers under PURA.
2. **Implementation of interconnection allowance.** The interconnection allowance offers a fairer distribution of upgrade costs, incentivizes DER deployment, and enhances grid resilience. The Commission should adopt the interconnection allowance for these reasons.
3. **Project size variances.** The cost of interconnecting a DER varies significantly based on the size of the project and the location of installation. Residential DERs, with their lower cost and localized impact, exist on one end of the spectrum, while larger-scale commercial batteries represent higher-cost, more complex and bespoke installations on the other end. The allowance should also be tiered to account for the differences between small and large DERs based on: less than 10 kW, between 10 kW and 500 kW, between 500 kW and 2 MW, and over 2 MW.
4. **Cost recovery.** Integrating cost allocation for DERs into DCRF proceedings ensures that all ratepayer classes benefit from improved grid resilience and just, reasonable rates. DERs should be recognized as essential tools for distribution system resilience, and their value must be considered alongside utility investments to better serve customers and mitigate peak demand.
5. **Advantage of localized DER implementation.** Residential DERs provide multiple benefits, including outage protection for customers, support for the grid by alleviating strain during peak demand, and targeting feeder-level capacity increases on the Distribution grid. Their deployment should be encouraged through equitable cost allocation mechanisms, such as the proposed interconnection allowance.
6. **Recommendation to prioritize interconnection issues.** We urge the Commission to prioritize implementing the recommendations in Project No. 54224 by the end of 2024 and to address separately the standardization of interconnection agreements and technical requirements for DERs under Project No. 54233 in 2025.

Respectfully submitted,

Tori Villarreal

Tori Villarreal
Head of Policy
Base Power
tori@basepowercompany.com