COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC INVESTIGATION OF	)	
INTERCONNECTION AND NET METERING	)	Case No. 2020-00302
GUIDELINES	)	

BRIEF OF KENTUCKY POWER COMPANY REGARDING INTERCONNECTION GUIDELINES AND FERC ORDER 2222

INTRODUCTION

The Public Service Commission of Kentucky ("Commission") initiated this administrative case on September 24, 2020 to "investigate and potentially modify and update net metering interconnection guidelines in light of the time since the establishment of those guidelines over a decade ago and to address the enactment of Senate Bill 100, An Act Related to Net Metering …"[1] On February 16, 2021, the Commission directed the parties to file written briefs "discussing current and reasonably anticipated issues and concerns" they have identified regarding "net metering interconnection guidelines, and, separately, current and reasonably anticipated concerns regarding Federal Regulatory Energy Commission (FERC) Order No. 2222."[2] Kentucky Power Company ("Kentucky Power" or the "Company") appreciates the opportunity and offers the following written comments.

DISCUSSION

I. Comments Regarding Net Metering Interconnection Guidelines

First, as a whole, the current Net Metering Interconnection Guidelines address only net metering interconnections; they do not discuss interconnection requirements if a customer does

[1] Order at 1 (Sept. 24, 2020).

[2] Order at 2 (Feb. 16, 2021); *see also* Order at 2 (Mar. 4, 2021) (extending the deadline for written briefs to April 19, 2021).

not qualify or is deemed ineligible for net metering during the review process. Under FERC Order 2222,[3] a customer (including a Qualified Facility ("QF") that intends to participate in a wholesale aggregation would not be subject to either the net metering rules or the COGEN rules, as the customer is not applying to take service under either the NMS or COGEN tariffs. Under FERC Order 2222-A, QFs are subject to state interconnection agreements even though they are otherwise subject to PURPA.[4]

Each of the following lettered sections contains the Company's comments relating to the corresponding section of the existing Interconnection Guidelines approved in Case No. 2008-00169.[5] Kentucky Power offers its comments as to each section of the existing guidelines in the same format as the existing guidelines for ease of reference.

a. Availability of Service.

The Availability section of the Interconnection Guidelines does not address Energy Storage Devices and non-renewable backup systems isolated behind a Make-Before-Break 'smart switch.' These devices could put energy back on to the grid; if not properly dealt with through interconnection guidelines, this could create service issues and damage the electric grid.

Further, this section presently does not define, or lacks clarity regarding, several key terms. For clarity and consistency among utilities and interconnections throughout the Commonwealth, the Commission should address this issue, to ensure the guidelines are clear and consistently followed by utilities, and that utilities all have a common understanding of what these terms mean and how they should be applied.

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[3] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (2020) ("Order No. 2222").
[4] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,197 (2021).
[5] Case No. 2008-00169, Order (Ky. P.S.C. Jan. 8, 2009).

First, this section does not fully define a 'customer.' Without such a definition, utilities, for example, may not have guidance on how to treat situations where the customer is a renter, or a customer whose premises or generating equipment is owned by a third party. Should Net Metering be limited only to those who own not only their own property, but also the generating equipment? Along those same lines, questions could arise as to who, in those instances, would sign an Interconnection Agreement. The Commission should define the term 'customer' for clarity and consistency of application between utilities.

Second, this section does not define 'operated.' What if a third-party is supplying maintenance and operation support for the system? What if the customer provides access to their equipment as part of a wholesale aggregation? What if the customer participates in some form of beneficial energy efficiency program that may alter equipment settings or expected equipment output?

Third, this section does not define 'is connected in parallel.' For example, does this definition apply in the situation of backup systems isolated behind auto-transfer and other smart switching devices that require paralleling for a period of time? Any instance of parallel operation, even if brief, should be reviewed and evaluated by the utility to ensure no adverse conditions are created that may damage equipment or otherwise be harmful to others.

Fourth, this section should provide additional clarity regarding capacity limitations. Does the rated capacity refer to the nameplate rating of the equipment? Does the rated capacity refer to the AC or DC rating? Does the rated capacity include the exportable capabilities of connected energy storage devices? Does the rated capacity include momentary export potential of backup systems?

Finally, this section should provide additional clarity regarding the meaning of systems rated to supply 'all or part' of a customer's electrical requirements. Does this mean the customer's kW, or kWh needs? What about oversizing of systems? Is there a threshold to how large a system may be? What is the minimum duration of this analysis (*i.e.*, if they oversupply in a month do they no longer qualify for net metering, or a year)? What if a system is rated to supply the customer's highest peak demand, which may result in over-production kWh in a given time frame?

b. Metering.

In addition to measuring inflow and outflow at the point of service, the Commission should consider that utilities also should be metering a customer's generation separately (or have the option to do so), unencumbered by the customer's non-generation load. The Commission also could consider defining guidelines more broadly allowing that multiple and different types of meters may be required at the discretion of the utility. Without such metering, the utility cannot accurately plan for load requirements and risks the inability to provide safe, adequate, and reliable service during times when the customer is not generating. Additionally, metering the generation gives the utility the ability to provide customers with a consistent source of information regarding the performance of their system over time. Moreover, although FERC Order 2222 opens the door to some inventive means of market participation, measuring actual generation data will allow the Company to analyze and monitor the actual performance of customer-owned generators as well as validate a customer-owned distributed energy resource's ("DER") continued compliance with interconnection requirements.

The Commission also should include provisions to indicate that additional costs may be borne by the customer or developer. In cases of no existing service, the Commission should provide utilities with the flexibility to require that such costs are borne by both an applicant and the developer/parent company with whom an applicant is working to install a DER. The Commission could do so by permitting utilities to require a customer to provide additional security or a guaranty. The Company has had multiple experiences in the last few years where new service interconnection is requested by a development company, which then creates a separate limited liability company ("LLC") only for purposes of applying for interconnection, and then abandons the application and dissolving the LLC when costs get too high. Doing so allows the developer apply for interconnection while shifting all the cost risk to the Company, and eventually, its customers. The Company requests that the Commission consider means to discourage the aforementioned practice and hold applicants accountable for costs incurred for an interconnection study.

c. Billing

The Company presently has no comments regarding this section of the Interconnection Guidelines but reserves the right to provide comments later in this proceeding.

d. Application and Approval Process

In the Company's experience, the person submitting an interconnection application rarely is the ultimate customer. Therefore, the Commission should include in the Interconnection Guidelines that responsibility for the application should fall on the applicant in addition to the customer. The Commission also should consider guidelines that will hold installers accountable, as oftentimes installers fail to provide the Company with required paperwork about an interconnection until after installation of a DER is completed. Installers can then use the fact the customer is already installed as a way to push through approval, as the customer may become dissatisfied or lodge complaints.

Moreover, the Commission should strengthen, or make more explicit, the language in the current Interconnection Guidelines that a customer-generator "…receive approval from the Utility prior to connecting the generator facility to the Utility's system." Failure to follow this section of the guidelines results in one of the largest systemic problems to the Company in processing applications.

Regarding applications, the Company highly recommends a single standard application that can be reviewed under multiple levels. If the Commission declines to implement a single standard application, the Commission should at least broaden the language in the guidelines to indicate that while the application initiates the process, the utility may ask for additional information at its discretion to properly review the interconnection request. Prior to the Company's implementation of PowerClerk, a DER interconnection application management software, there was significant confusion from customers around which application or agreement needed to be submitted.

The Commission should also separate the application and agreement processes in the Interconnection Guidelines. During the application process it is common for originally-submitted details to change, either because of human error, changed requirements, or being incomplete. As such, customers often must sign the same document twice to account for these changes: first to attest that they are in fact applying for interconnection and that the information is accurate to the best of their knowledge; and second to make sure the final, correct application is signed. Requiring signature on the final, correct agreement ensures that the agreement actually references what is really approved, and not what the installer drafts. The way the Application/Agreement currently is set up, it creates a likelihood that the Company signs binding agreements with customers with inaccurate information.

The Commission also should consider broadening or adding signature requirements for all parties invested in the interconnection (service customer, system operator, system owner, and utility). The current Interconnection Guidelines do not address the issue of potential third-party ownership of the generating system or the premises where the customer is located.

The Commission also should consider changing the Level 1 and Level 2 processes to an escalating system rather than independent processes. Failure under Level 1 should not result in a rejection, but should instead advance to Level 2 for a more robust screening before requiring a full Distribution Impact Study. By one of those methods the Company would be able to fully determine the impacts of the interconnection on the system and identify necessary enhancements and upgrades to the Area Electric Power System ("EPS") to safely support the interconnection. Level 2 should also have screening criteria, as many systems in the range of 45-500 kW can be reviewed by screening and found to interconnect safely with some or no EPS upgrades. Such changes would aim to reduce the burden on the customer and provide them an answer as efficiently as possible. Forcing the customer to resubmit a failed application under the next level is unnecessary and results in more work and resources on the part of all parties. It also creates unnecessary work for the utility to review the same information twice. The utility should be able to escalate a given application through increasingly more technical reviews until the scope of system impacts can be determined and mitigation requirements can be identified.

The Commission should further consider adding an online method (at least as an option) for applications. Online applications also may be an opportunity for utilities to more clearly list the utility representatives on their own website and provide links to the relevant utility webpages for information and the application portal.

Finally, the Commission should consider more fully explaining in the Interconnection Guidelines what information is expected to be submitted in the application process. The Commission should consider the following:

- Customer – Is this the actual Service holder? What about third-party ownership? What about the case of spouses, where one spouse is listed on the account, but the other is not? What are the limitations on who may or may not sign an interconnection agreement for a system? What if a system is being paid for by a parent, but installed on the premise of, and will be utilized by the child?
- Customer Address – Is this the customer's service address, contact address, billing address, or the address of the physical DER installation?
- Project Contact Person – In the Company's experience, this field creates significant confusion, and would benefit from clarification. Should this be the person the utility is contacting in matters about the application, or is this the installation representative? What if the utility has a question that the customer must answer, does the installer have the right to answer on the customer's behalf if listed here?
- Proof of Insurance – General liability coverage is important to ensure that unsafe operation resulting in property damage or personal injury will be covered by the customer. Some states set a value (typically $100,000 for residential), but any insurance covering the system is important, similar to motor vehicle insurance.
- Technical Data – The current Interconnection Guidelines provide no explanation for many of the technical fields regarding the units of these fields or the content required. Additionally, more and more systems are installing backup systems, not just batteries, and that information should also be requested. The application also is silent as to

possible hybrid systems (i.e. solar and wind). The application further does not indicate whether the project is an expansion or alteration of system data, nor does it clarify if the application should reflect *only* the newly installed equipment, or if it should describe all electrical equipment that will be in operation, which the Company recommends.

Further, the specification sheets for all electrical equipment (generator/panels, inverters, batteries, backup generators, customer owned transformers, relays, protective fuses, etc.) should be included with the application.

The Company recommends that the Commission include in the Interconnection Guidelines that the interconnected system should also be allowed to qualify under IEEE 1547.

The Commission should consider that the site diagram show the location of the meter, the A/C disconnect switch, major electrical equipment (generators, inverters, etc.), and major structures and landmarks on the property (i.e. buildings, fences, etc.). It also should indicate or show interior versus exterior equipment.

The Commission also should consider that the single line diagram (electrical one-line diagram) should be stamped by a Professional Engineer for systems above 50 kW-AC (or 45 if tied to the Company's level 1/level 2 divide). The complexity of connecting larger systems to the grid requires specialized electrical engineering knowledge.

The Commission also should consider that information regarding generating data (fixed/tracking, roof direction, azimuth angle, hours of daylight, etc.) should be provided to the utility in order to confirm certain assumptions made in selling systems to customers, and to confirm the systems are the correct size. The latter considering is especially important if utilities can enforce a 'right sizing' of systems.

- Deadlines/Timeframes – This issue can be contentious, and the Commission should consider including timeframes for submitting an application a minimum number of days prior to connecting a system. The Commission should also consider including a timeframe for times when an applicant is not responsive, and how long their application must be kept 'active' before a utility may remove it from the queue.

e. Level 1

The Commission should consider an option to escalate the application from Level 1 to Level 2 Screen and Level 2 Screen to a Distribution Impact if the generator does not pass the Level 1 screen. Moreover, an application being approved should not instantly force the signing of the Interconnection Agreement. In the Company's experience, this practice has resulted in numerous issues with customers and installers across the AEP system who take the companies' signing of the Interconnection Agreement (even if restrictions and other conditions are clearly stated) as evidence that the Company should no longer be involved. The Company recommends that the Commission provide that the Interconnection Agreement be a separate document from the application, and the agreement should not be signed until the customer has submitted proof that their installation is complete and has been inspected fully.

f. Level 2

In the Company's experience, applications not meeting one of the Level 1 thresholds (i.e. greater than 45 kW) are still reviewed based on screening questions functionally similar to Level 1. AEP officially uses the FERC SGIP screening questions, which largely are the same as the Level 1 questions. Moreover, the way the current guideline is written implies that a Level 2 application would require an Impact Study, which often is not the case.

The Commission also should consider lengthening the time to complete a Distribution Impact Study from 30 days to 90 days. The current time to complete a Distribution Impact Study, 30 days, creates a significant burden on Distribution Planning to reassign or rapidly bring on contracting resources to meet the deadline. In unencumbered situations, delivery of an Impact Study normally can be completed between 60 and 90 days from receiving a signed Impact Study Agreement.

The Company also recommends that the Interconnection Guidelines create a formal requirement that an Impact Study be done with the consent of the individual. More specifically, the guidelines should include a formal requirement that if the impact study is deemed necessary, it is to be performed only after consent is given by the customer, and financial responsibility for the work is assigned and made clear. Moreover, as explained previously, the applicant (which typically is an LLC) as well as the parent company should commit to bear the financial responsibility.

g. Application, Inspection and Processing Fees

Due to the increased penetration of DERs on the Company's system, a significant increase in "+Storage" systems, and FERC Order 2222, is it vital that the Company have greater visibility on the performance of customer owned generators. For these reasons, the Interconnection Guidelines should require that a generation/production meter be installed for all new systems.

h. Terms and Conditions for Interconnection

The Company presently has no comments regarding this section of the Interconnection Guidelines but reserves the right to provide comments later in this proceeding.

II. Comments Regarding FERC Order 2222

On September 17, 2020, FERC issued Order No. 2222 "to remove barriers to the participation of distributed energy resource aggregations in the Regional Transmission Organization ('RTO') and Independent System Operator ('ISO') markets[.]"[6] FERC Order 2222 is directed toward the RTO and ISO market rules and tariff changes that would be needed to accommodate the participation of such aggregations in the wholesale energy and capacity markets. FERC made clear that it was not interfering with state regulation of the distribution system, stating:

> the Commission recognizes a vital role for state and local regulators with respect to retail services and matters related to the distribution system, including design, operations, power quality, reliability, and system costs… we reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements.[7]

Kentucky Power continues to evaluate FERC Order 2222 from multiple perspectives, but primarily to ensure that the safety and reliability of the distribution and transmission systems are maintained. At this time, it is Kentucky Power's position that the continued safety and reliability of those systems can be supported by (i) appropriate interconnection rules for all DERs[8] intending to interconnect to its system; and (ii) continued, system-wide operational control by Electric Distribution Companies to address operational limitations and system instability conditions (e.g., override capability). Kentucky Power expects that its positions will develop and

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[6] Order No. 2222.

[7] Order No. 2222 at P 44.

[8] FERC defines "a distributed energy resource as any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment. *See* Order No. 2222, 172 FERC ¶ 61,247 at PP 1 n.1, 114.

be refined as rules and wholesale tariff provisions to implement FERC Order 2222 are finalized. PJM Interconnection, LLC's ("PJM") compliance filing is due February 1, 2022.[9]

a. Distributed Energy Resource Interconnection Guidelines

Kentucky Power is in the process of reviewing its current DER interconnection process and determining what new or modified interconnection rules or processes will be necessary to properly interconnect a growing number of DERs. For example, the impact analysis may need to be augmented to account for the simultaneous dispatch of multiple DERs. Additionally, cost responsibility for distribution system reliability and other upgrades caused by interconnected DERs should be clear. Kentucky Power is also considering metering and telemetry requirements that would be required to accommodate wholesale market participation, as a component of interconnection agreements.

It is also important to note that resources located behind the retail meter are included within the definition of DERs that may participate in DER aggregation. As a result, resources currently interconnected as "net metered resources" and resources that choose in the future to interconnect as "net metered resources" may have the opportunity to participate in wholesale markets as part of a DER aggregation. As a result, there is not a bright line separating net metered interconnections from other DER interconnections. At a minimum, the Commission and electric utilities in Kentucky must consider whether a process is needed to accommodate the conversion of an interconnection from a net metered resource interconnection to a standard DER interconnection.

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[9] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 175 FERC ¶ 61,103 (2021).

b. Anticipated Distribution System Investments

Kentucky Power will need to prepare for the evolving grid by investing in new systems and tools. These systems and tools must ensure Kentucky Power has a robust, flexible architecture in place to continue to safely, reliably and securely manage its distribution grid, including but not limited to the ability to:

- track interconnection status of all DER types;
- monitor customer enrollment in state, federal, and RTO DER programs;
- meter and potentially override the dispatch of individual DERs; and
- provide for settlements as required by each DER's program participation.

The paradigm presented with FERC Order 2222 accelerates the need for new operational technology systems, which will allow for situational awareness on the distribution system (much like what is required for the transmission system). An Advanced Distribution Management System operating technology system introduces a comprehensive integration between Outage Management System and Distribution Management System systems. A Distributed Energy Resource Management System introduces the ability to manage DERs integrated into the distribution grid and support retail customers' aggregated participation in wholesale markets. These systems will allow for accurate and efficient data exchanges between Transmission and Distribution system operators and ultimately provide SAIDI improvement opportunities into the future.

Finally, it is important to note that costs associated with the interconnection of DERs are volumetric. Therefore, as interest and participation in DER programs grow, costs to support and manage them will also increase.

c. Other Considerations.

As mentioned above, rooftop installations such as those that would typically participate in net metering may also participate in the wholesale energy and capacity markets through a DER aggregation. As a result, rules may be necessary to prevent Kentucky Power's retail customers from paying for the energy such resources provide twice – once through net metering and again as an aggregated energy resource Kentucky Power procures through the PJM market. For example, as FERC recognized:

> relevant electric retail regulatory authorities continue to have authority to condition participation in their retail distributed energy resource programs on those resources not also participating in RTO/ISO markets, which should allow them to mitigate any double-compensation concerns.[10]

Additionally, the Commission should consider minimum time frames for which a resource must choose to either be net metered or participate in a DER aggregation to minimize the administrative burden associated with customer-owned resources switching back and forth between retail and wholesale market compensation.

[10] Order No. 2222 at P 162 (internal reference omitted).

CONCLUSION

Kentucky Power looks forward to continuing to discuss these topics with the Commission and stakeholders as these proceedings continue, as well as after PJM submits its compliance filing regarding FERC Order 222 in February 2022.

Respectfully submitted,

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