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COMMISSION

October 10, 2019

Gwen R. Pinson
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Public Comments from the Kentucky Office of Energy Policy on Implementation of the Net Metering Act
Case No. 2019-00256

Dear Ms. Pinson:

Enclosed please find and accept for filing the Kentucky Office of Energy Policy's initial public comments for Case No. 2019-00256 concerning the implementation of the Net Metering Act.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Rick Bender

Rick Bender
Executive Director
Kentucky Office of Energy Policy

cc: Secretary Charles Snavely, Kentucky Energy and Environment Cabinet (via electronic mail)
John Horne, Kentucky Energy and Environment Cabinet (via electronic mail)

RECEIVED
OCT 10 2019
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC CONSIDERATION OF THE IMPLEMENTATION OF THE NET METERING ACT	) CASE NO: 2019-00256

INITIAL COMMENTS FROM THE KENTUCKY OFFICE OF ENERGY POLICY

The Kentucky Office of Energy Policy ("Office" or "OEP") provides the following initial public comments in response to the July 30, 2019 order of the Kentucky Public Service Commission ("Commission") in this docket. In the order, the Commission solicited input from interested parties to consider the implementation of Senate Bill 100, An Act Related to Net Metering (Net Metering Act), which takes effect on January 1, 2020. The Commission stated that the purpose of the proceeding is to invite comments from interested utilities and stakeholders to develop a record which the Commission can draw upon as it considers broad issues of implementation of the Net Metering Act as they apply to individual utilities.

As defined by the Net Metering Act, net metering is the difference between a) the dollar value of all electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period at prices established by the Commission through the ratemaking process (the compensation rate); and b) the dollar value of all electricity consumed by the eligible customer-generator over the same billing period that is priced under a retail electric utility's tariff rate. The Net Metering Act requires the Commission to establish the compensation rate during a ratemaking proceeding initiated by a retail electric utility, or a generation and transmission cooperative on behalf of one or more retail electric utilities.

As explained in more detail, the implementation of the Net Metering Act including the establishment of compensation rates and rate designs presents challenges and opportunities for both retail electric utility customers and Kentucky's regulated electric utilities.

I. Introduction

The Kentucky Office of Energy Policy is housed within the Kentucky Energy and Environment Cabinet. The Office's mission is to support the utilization of all of Kentucky's energy resources for the betterment of the Commonwealth while protecting and improving our environment. The Office works to address energy policy with a common-sense approach that ensures the Commonwealth thrives amid rapid changes occurring in the production, delivery, and use of energy.

Before moving forward, the OEP will explain the varying terminology used in these comments:

- Eligible Customer Generator is a specific definition under KRS 278.465 and means a customer of a retail electric supplier who owns and operates an electric generating facility that is located on the customer's premises, for the primary purpose of supplying all or part of the customer's own electricity requirements.
- Eligible Electric Generating Facility under KRS 278.465 means an electric generating facility that: Is connected in parallel with the electric distribution

system; and generates electricity using solar energy; wind energy; biomass or biogas energy; or hydro energy; and has a rated capacity of not greater than 30 kilowatts (45 kilowatts effective January 1, 2020).

- Distributed Energy Resource (DER) refers to energy resources connected to the distribution system (<69 kV voltage level) that either generate electricity, store electricity, or involve load changes in response to signals. DERs may be utility owned or customer-owned resources.
- Distributed Generation (DG) is a subset of DER and refers to those distributed energy resources that generate or store electricity for delivery to the electrical grid and includes the eligible electric generating facilities under KRS 278.465 and those connected under utility tariffs filed under the regulation for Small Power Production and Cogeneration.[1]

The National Renewable Energy Laboratory (NREL) provides an overview of distributed generation billing mechanisms and compensation mechanisms including net metering, net billing, and buy-all\sell-all.[2] All of which will be referenced in the following comments.

Annually, the OEP conducts a voluntary survey of utilities across Kentucky to assess the distributed renewable generator interconnections. For 2018, Kentucky had approximately 34 megawatts of distributed renewable generator interconnections with approximately thirty percent (30%) being interconnected via net metering and approximately seventy percent (70%) interconnected via a non-net metering arrangement. Of those interconnections, approximately eighty percent (80%) were

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[1] https://apps.legislature.ky.gov/law/kar/807/005/054.pdf

[2] https://www.nrel.gov/state-local-tribal/blog/posts/back-to-basics-unraveling-how-distributed-generation-is-compensated-and-why-its-important.html

considered to be solar-powered. The approximate 1,500 interconnections in 2018 were geographically dispersed across Kentucky.

Historically, the region of the state served by the Tennessee Valley Authority (TVA) exhibited the greatest distributed renewable penetration due in part to a feed-in-tariff program where distributed electricity produced was sold at rates higher than retail. It should be noted that the local power companies served by TVA do not offer net metering arrangements but utilize a billing mechanism known as buy-all\sell-all through the Green Power Providers Program.[3] The TVA model provides a useful comparison to trends occurring today in terms of compensation rates. Changes to the TVA Green Power Providers program illustrate that as TVA's incentive programs deliver expected outcomes, programs and policy structures change to meet market conditions.

Today, the TVA Green Power Providers Program compensates residential customers at nine cents per kWh, effectively compensating small solar generation near the residential retail rates charged by TVA local power companies in Kentucky. Notable distinctions with TVA Green Power Program include (1) TVA's completion of a value of distributed generation methodology assessment that illustrated a compensation rate much lower than 9 cents per kWh; (2) TVA historically minimized any intra-class cost shifting by using a buy-all\sell-all compensation framework for the Green Power Program; and (3) the Green Power Program will be retired after 2019 indicating how the program evolved to meet outcomes and proving that programs are not indefinite once outcomes are achieved.

[3] https://www.tva.com/Energy/Valley-Renewable-Energy/Green-Power-Providers/How-the-GPP-Program-Works

As residential retail energy rates have approached pricing parity with the cost of producing solar, the penetration of distributed solar interconnections has increased in Kentucky. Looking at retail variable electricity rates compared to the Levelized Cost of Energy (LCOE) from the Annual Technology Baseline[4] illustrates the anticipated pricing parity expected to occur across Kentucky in 2020. For instance, the largest growth rate in penetration of distributed renewable interconnections recently has been observed in the Big Rivers Electric Corporation region of Kentucky.

In response to growing distributed solar generation, the OEP partnered with NREL to model the future growth of distributed solar generation in Kentucky using the Distributed Generation Market Demand Model (dGen) assuming full retail rate net metering.[5] In summary, the total installed distributed solar generating capacity could range from 162 megawatts to 3,160 megawatts with a midrange of 2,124 megawatts by 2040 for the combined territories of East Kentucky Power Cooperative, Big Rivers Electric Corporation, and Louisville Gas and Electric\Kentucky Utilities. These adoption rates in 2040 represent a range of one percent to eighteen percent of the technical potential of rooftop solar in Kentucky. By comparison, Kentucky's utility scale power plants operating capacity is currently just over 20,000 megawatts.[6]

The OEP acknowledges the optimistic nature of the NREL projections by assuming the continuation of retail rate net metering and this should be viewed as an upper bound estimate. The change in the billing and compensation mechanism by the

[4] https://atb.nrel.gov/electricity/2019/index.html?t=sr
[5] Projections of Distributed Photovoltaic Adoption in Kentucky through 2040, Pieter Gagnon and Paritosh Das, June 2017
[6] S&P Global Market Intelligence Power Plant Screener

Net Metering Act, in 2019, is anticipated to slow the growth of distributed renewable generation but contrary to some rhetoric, is not anticipated to "kill" the distributed renewable generation industry in Kentucky. In fact, the Lawrence Berkley National Laboratory (LBNL), in 2015, illustrated how various rate design changes affect distributed solar deployment.[7] Relevant to the questions before the Commission, the LBNL partial net metering scenario (solar generation that displaces instantaneous load compensated at retail rates and solar generation exported to the grid compensated at avoided-cost rate) could be construed as offering a middle ground in comparison to other rate design options involving changes to the residential rate class as a whole, more on this in the following sections.

II. Keeping Customers Connected and Growing Complexity

The OEP applauds the Commission and the leadership it has exhibited in commencing this docket. Indeed, according to the *50 States of Solar Report Annual Review for 2018*, Kentucky is not alone in tackling the evolution of net energy metering (net metering). Actions relating to solar policies, net metering, and rate design around distributed generation occurred across 47 states plus the District of Columbia in 2018.[8] The Report notes for 2018 that compensation frameworks and program designs are growing increasingly complex, a topic addressed later in these comments, and one essential for consideration by the Commission moving forward.

> *"A record number of states considered net metering changes in 2018, with compensation structures becoming increasingly complex. Some programs feature*

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[7] https://emp.lbl.gov/sites/all/files/lbnl-183185.pdf
[8] https://nccleantech.ncsu.edu/wp-content/uploads/2019/01/Q4-18-Exec-Summary-Final.pdf

separate rates for energy imports and exports, while others include time-varying rates, value-based rates, and locational components."

In addition, the Report points out major policy and regulatory themes across the United States:

- Policymakers and Regulators Authorizing Solar-Plus-Storage Net Metering
- Regulators Approving Residential Demand Charges for Distributed Solar Customers
- Companies Seeking Clarity on Solar Leasing Legality
- Solar Policies Being Addressed Within the Broader Scope of Grid Modernization
- Requests to Significantly Increase Residential Fixed Charges Slowing
- Mixed Decisions on Separate Customer Classes for Distributed Generation Customers
- Increasing Customer Choice in Distributed Generation Rate Options
- Exploring the Locational Value of Distributed Generation

What is evident from the above list and the evolution of state action is that changes to net metering policies are rarely a one and done action. For Kentucky and the Commission, the evolution of net metering has just begun with the Net Metering Act. As technologies and penetration of distributed generation sources change, so will the need of policies and regulations to support those changes. This is supported by the National Association of Regulatory Utility Commissioners (NARUC) in the *Distributed Energy Resource Rate Design and Compensation* Manual.[9] The Manual is clear in providing direction for state regulatory commissions assessing compensation methodologies.

"It is imperative that a regulator understand the tradeoffs in determining an appropriate compensation methodology, both in terms of technology adoption

[9] https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

(does the methodology emphasize one technology over another; what does that mean to the market and the utility?) and over time (does the methodology encourage adoption of specific technologies in the short term as opposed to allowing a variety of technologies to develop over time to meet grid needs?)."

This quote from the NARUC manual also highlights an important consideration for the Commission— keeping customers connected to the system. As explained by the Manual,

> *"It is believed that keeping people connected to the grid creates additional value to the customer, the utility, and society in general. This belief mimics a variety of so-called "laws," such as Metcalfe's law and Reed's law, which all posit that the value of a network increases the more things (or people) that are connected to it. On the electric utility side, it seems apparent that having more devices connected to the grid inherently enhances the value of the grid and the devices connected to it. If nothing else, having less people connected to the grid would seem to decrease the value of the grid. This is important because if customers decide to disconnect from the grid due to policies discouraging DER or erecting barriers to entry for DER, the costs of maintaining that system falls onto fewer and fewer customers; thus, the value of the grid is minimized. Therefore, it is important to recognize that there is a value from the grid not only for the provision of electric service, but also for enabling and integrating a greater number of devices that can be utilized by a greater number of other devices and customers connected to the grid."*

As such, the Commission plays a pivotal role in ensuring customers stay connected to the system in order to accomplish its mission of:

> *"foster[ing] the provision of safe and reliable service at a reasonable price to the customers of jurisdictional utilities while providing for the financial stability of those utilities by setting fair and just rates, and supporting their operational competence by overseeing regulated activities."*[10]

[10] https://psc.ky.gov/Home/About

Through the following comments, the OEP will navigate the complexity of rate design and compensation methodology relating to the Net Metering Act, highlight specific considerations for the Commission regarding implementation, and provide insights into future issues relating to net metering. The comments provided highlight issues from the perspective of Kentucky's regulated utilities, customers across the Commonwealth, and the distributed energy resource industry as a whole.

III. Historical Context of Net Metering Remains Important

Before taking up the task of detailing specific issues around the Net Metering Act, it remains an important task to understand the historical context of net metering and the role that net metering played and plays in the larger regulatory framework of connecting distributed generating resources to the electric grid.

Traditional net energy metering (net metering) began by accident in 1979 in Massachusetts. A 28-year old architect, Steven Strong, installed solar photovoltaic (PV) panels in two building projects, a 270-unit apartment complex called Granite Place with a 5-kilowatt system added on, and a Department of Energy funded solar house called the Carlisle House with a PV system integral to its design.[11] According to Mr. Strong's accounts of the incident, the utility (Boston Edison) was unaware that net metering was already happening because when the PV system was connected to the meter, the meter ran both forward and backward depending on the solar production and electricity consumption of the housing units. By default, the power produced onsite from the solar project offset the power consumed onsite and any excess was exported to the electric

[11] https://cleantechnica.com/2015/09/06/net-metering-history-logic-part-1/

grid at a value equal to the consumption price (retail rate). Consequently, Net Energy Metering (NEM) as a billing mechanism was born with little to no forethought to the future, as evidenced by the debates ongoing today.

Around the same time as the advent of net metering, a different compensation mechanism was developing. The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted following the energy crisis of the 1970s to encourage cogeneration and renewable resources and promote competition for electric generation. The act requires electric utilities to purchase electric energy from cogeneration facilities and small power production facilities of 80 megawatts (MW) or less in size at a rate that does not exceed the incremental cost to the electric utility of alternative electric energy (referred to as "avoided cost"). The Federal Energy Regulatory Commission (FERC) and the states were directed to implement PURPA, with FERC determining what constitutes a qualifying facility (QF) and providing guidance on avoided costs. State public utility commissions have responsibility for determining the avoided costs for the utilities they regulate and to establish the rates, terms, and conditions of power purchase contracts and interconnection.[12] What is most important about PURPA, is that, contrary to net metering, the power that is exported from to the electric grid is valued at the wholesale rate or avoided cost of the utility.

As demonstrated above, connecting renewable distributed generation sources to the electric grid followed two separate and conflicting compensation methodologies as states implemented PURPA and adopted net metering laws.

[12] https://www.publicpower.org/policy/public-utility-regulatory-policies-act-1978

FERC further weighed in on net metering to clarify federal jurisdictional issues and draw specific distinctions between net metering compensation and that of PURPA.[13]

- *"In Order No. 2003-A, the Commission [FERC] described net metering as follows: Net metering allows a retail electric customer to produce and sell power onto the Transmission System without being subject to the Commission's [FERC's] jurisdiction. A participant in a net metering program must be a net consumer of electricity -- but for portions of the day or portions of the billing cycle, it may produce more electricity than it can use itself. This electricity is sent back onto the Transmission System to be consumed by other end-users. Since the program participant is still a net consumer of electricity, it receives an electric bill at the end of the billing cycle that is reduced by the amount of energy it sold back to the utility. Essentially, the electric meter "runs backwards" during the portion of the billing cycle when the load produces more power than it needs, and runs normally when the load takes electricity off the system."*
- *"The Commission [FERC] has explained that net metering is a method of measuring sales of electric energy. Where there is no net sale over the billing period, the Commission [FERC] has not viewed its jurisdiction as being implicated..."*

Two important distinctions are evident. First, net metering's billing mechanisms are based on "credits" on the customer's bill while a PURPA customer is engaged in making a net sale to the utility. Second, FERC established that net metering under certain conditions was not a federal jurisdictional issue and falls to state regulatory entities.

In Kentucky, the Kentucky Public Service Commission implemented PURPA through 807 KAR 5:054[14] in 1982. Net metering followed in 2004 via KRS 278.465-468

[13] https://www.ferc.gov/whats-new/comm-meet/2009/111909/E-29.pdf
[14] https://apps.legislature.ky.gov/law/kar/807/005/054.pdf

and was amended in 2008 and again in 2019. One may construe from the regulatory history in Kentucky that given an existing compensation framework under PURPA for connecting renewable distributed generation systems was in place, the legislative intent in adopting net metering was to allow for a separate and distinct billing mechanism for smaller distributed renewable systems to encourage or incentivize greater customer adoption. The same conclusion could be drawn from amendments in 2019 in that there was no repeal of net metering but rather a modification, signaling the continued desire to serve smaller renewable distributed generation customers under a separate compensation rate and framework than currently offered by PURPA tariffs.

The OEP recommends that the Commission consider reviewing PURPA tariffs for Kentucky's regulated utilities in comparison to the language in the Net Metering Act with special attention to the distinguishing features outlined by FERC and considering that partial net metering (or net metering until export occurs) is allowed per 807 KAR 5:054 Section 7(a), where a qualifying facility is permitted to use the "output of the qualifying facility to supply their power requirements and selling their surplus."[15] A question for further evaluation is how the implementation of these tariffs is different than that language in the Net Metering Act, ensuring that PURPA tariffs, as implemented, make a "sale" and not engage in dollar denominated credits.

For example, the Louisville Gas & Electric Tariff for Small Capacity Cogeneration and Small Power Production Qualifying Facilities (100kW or less) does make it clear in the tariff language that there is a sale and purchase of electricity; but in practicality under the Payments section, confusion arises as dollar credits may be interpreted as

[15] https://apps.legislature.ky.gov/law/kar/807/005/054.pdf

being utilized if the seller is a customer of the utility. This language calls into question how this billing arrangement is different than that in the Net Metering Act.

> *"Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of Company's reading of meter; provided, however, that, if Seller is a Customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as Customer."*[16]

The OEP acknowledges that the 2019 amendments were largely focused on addressing the potential intra-class cost shifting that may be occurring within the residential class, acknowledging that intra and inter-class cost shifting can occur from various policies and programs under current ratemaking methodologies. The NARUC Manual is specific and points to the importance of adoption levels in the Commission's considerations:

> *"Cost shifting, or subsidies, is unavoidable in practical rate design but regulators endeavor to mitigate these effects in the larger context of the many, often conflicting, rate design principles....At a low level of adoption, this may be considered merely another imperfection in rate design, but at large levels of adoption it can be problematic and represent large amounts of revenue being shifted to other, non-DER customers in the same rate class."*[17]

Other than the distinctions outlined by FERC in billing and compensation, two additional distinctions exist for net metering in Kentucky: (1) net metering customers in Kentucky have historically enjoyed consistency in the interconnection application and

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[16] https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf
[17] https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

approval process across all regulated electric utilities and (2) standard interconnection guidelines exist across all regulated utilities for existing net metering customers. These standard processes and requirements are detailed in the *Interconnection and Net Metering Guidelines-Kentucky* issued by the Commission.[18]

Given this historical context, the OEP urges the Commission to consider evaluating all proposed compensation rates and methodologies in the context of net metering being separate and distinct from PURPA tariffs, evaluating PURPA tariffs as implemented to ensure a "sale" occurs and not utilizing dollar denominated credits, evaluating how net metering tariffs complement and coordinate with PURPA tariffs, to the extent possible, while complying with the Net Metering Act, and retain the existing characteristics of simplicity, consistency, and interconnection standardization across regulated utilities in Kentucky. The OEP acknowledges the difficulties in balancing these potentially conflicting principles and elaborates on these important intricacies in the following sections; however, the overarching question of how net metering fits into an overall policy framework (including PURPA) for connecting distributed energy resources remains a key evaluation question for the Commission moving forward.

IV. Adherence to Core Principles of Ratemaking and Rate Design

There is little dispute that the source of modern ratemaking and rate design theory is the foundational text, *Principles of Public Utility Rates* by James C. Bonbright. Even today's complex questions around markets, distributed energy resources, can be addressed by adherence to the core principles outlined in the Bonbright text. The crux

[18] https://www.psc.ky.gov/agencies/psc/Industry/Electric/Final%20Net%20Metering-Interconnection%20Guidelines%201-8-09.pdf

of the issue facing this Commission concerning the Net Metering Act is the same issue faced by Justice Jackson in 1944 in the dissent on the *Federal Power Commission v. Hope Natural Gas Company.*[19]

> *"I must admit that I possess no instinct by which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision."*

As Bonbright explains, "sound ratemaking policy is a policy of reasonable compromised among partly conflicting objectives."[20] The issue of net metering compensation rate before the Commission exemplifies this statement today and it is the task of the Commission to establish some conscious design in determining the reasonableness of proposed net metering compensation rates and tariff designs moving forward.

A second core principle outlined by Bonbright but is often lost in conversations is that of *consumer sovereignty.* Distinctly different from socialized services, public utility services, for the most part, adhere to the principle that consumers of public utility services should be free to take whatever types and amount of services they are ready to pay for and in return, therefore, should be required to pay rates not seriously out of line with costs of rendition of those services. While the net metering customer is freely choosing to exert more control over the consumption of utility services, the customer is still receiving services from the utility. The issue up for evaluation is what compensation rate for the net metering customer's exported electrical generation is not seriously out of line with the costs of rendition of utility services. In this instance, costs may be interpreted to mean net costs of rendition, assuming the net metering customer provides

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[19] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 at 645 (1944)
[20]Bonbright, James C., *Principles of Public Utility Rates* (Columbia Press, 1961)

benefits back to the utility, and that the utility can accurately estimate these net costs of rendition — more on this point in later sections.

In general, utility commissions have latitude in making the judgement on what rates are "not seriously out of line" with costs of rendition. Bonbright admits "Satisfactory results, not ideal or optimum results, are all that can be expected of the ablest group of rate makers." The problem before the commission is best highlighted by the NARUC manual in a discussion on traditional ratemaking[21]:

> *"In sum, under the traditional ratemaking model and commonly used rate design, if the utility passes its relevant threshold of DER adoption, the utility may face significant intra-class cost shifting and erosion of revenue in the short run. If left unaddressed, the utility could face pressures in the long term that might prevent it from recovering its sunk costs, which are necessary to provide adequate service."*

Consequently, the OEP encourages the Commission to consider the eight attributes of sound rate structures identified by Bonbright when evaluating proposed compensation rate structures submitted under the Net Metering Act.[22]

1. Rate structures should have attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Rate structures should have freedom from controversies as to proper interpretation.
3. Rate structures should be effective at yielding total revenue requirements under the fair-return standard.
4. Rate structure should ensure revenue stability from year to year.

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[21] https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0
[22] Bonbright, James C., *Principles of Public Utility Rates* (Columbia Press, 1961)

5. Rate structures should have stability in the rates themselves with minimum unexpected changes.
6. Rate structures should be fair in the apportionment of total costs of service among different rate classes.
7. Rate structures should avoid undue discrimination in the rate relationships.
8. Rate structures should be efficient by discouraging wasteful use of service while promoting all justified types and amounts of use (both total amounts of service and time differentiated amounts of service).

In effect, a well-designed compensation mechanism and rate structure under the Net Metering Act will mitigate any negative effects, reinforce positive effects, and support the full and fair benefits and costs of distributed generation resources to utilities, renewable system owners, and to all other customers.[23]

V. Cost of Service Ratemaking versus Value of Service Ratemaking

There is little doubt that the most prevalent interpretation of "reasonableness" in ratemaking is that of the cost of service standard evidenced by the adoption and use within utility regulatory environments nationwide. This cost based standard draws stark contrast to other models such as competitive pricing standards or value of service standards. In Kentucky, this is illustrated by the Commission's presentation to the Interim Joint Committee on Natural Resources and Energy wherein the rate design process outlined highlighted the use of costs of service studies in the allocation of the utility revenue requirement to each customer class.[24] Bonbright highlights that "one of the reasons for the popularity of cost of service standard of rate making lies in the

[23] https://www.nrel.gov/docs/fy18osti/68469.pdf

[24] https://apps.legislature.ky.gov/CommitteeDocuments/262/11977/Aug%2020%202019%20KYPSC%20Mathews%20PowerPoint.pptx

flexibility of the standard itself".[25] It is this inherent flexibility that remains crucial for the Commission in the evaluation of costs as it pertains to the Net Metering Act.

However, the OEP highlights concerns associated with the loose interpretation of costs to the point of societal ratemaking through an inadvertent shift to a value of service standard rather than cost based standard. Value of service in this context refers to the worth of the service to consumers as a measure of their willingness to pay. By default, the value of service methodology does not lend itself easily to quantitative expression as a measure of reasonableness. In a perfectly quantifiable world, the most reasonable rate may be one that is intermediate between the cost of production of electricity and the value that the electricity provides to customers and/or society. In practice, however, the Commission can assess all necessary and prudent cost categories (and related benefits) within the cost of service framework that would reinforce its continued use in the context of the Net Metering Act.

For added complexity, many states have adopted a Value of Solar (VoS) methodology as illustrated by the ICF report "*Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar*".[26] By in large, most methodologies cited are an exercise in costs and benefit category evaluation and quantification rather than a true valuation in the context of societal or social principles of ratemaking. In the context of the Net Metering Act, the Commission may utilize the so called VoS studies to identify benefit/cost categories for evaluating the comprehensiveness of utility compensation rate proposals under Kentucky's existing cost of service framework. One

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[25] Bonbright, James C., *Principles of Public Utility Rates* (Columbia Press, 1961)
[26] https://www.icf.com/blog/energy/value-solar-studies

such framework, for reference, would be the process and methodology outlined in the TVA's "*Distributed Generation-Integrated Value Report*".[27]

To be clear, societal ratemaking as a departure from cost based ratemaking, involves the supply of utility services responsive to social needs and costs.[28] While societal value considerations can be considered indirectly by commissions in ratemaking, the task of ratemaking per Bonbright, is "one of fixing values, not of finding them—of bringing the prices of public utility services into line with the prices of other projects by relating the former prices to the costs of production." Any departure from cost of service ratemaking, can best be categorized as being due to political, business, or administrative reasons rather than true social reasons, for a true departure from cost of service ratemaking to social ratemaking would ultimately result in the socialization of utility services, well beyond the scope of consideration in this proceeding.

The OEP does recommend that the Commission move cautiously and acknowledge that utility rates are ineffective instruments by which to minimize societal costs and maximize societal benefits. Any move by the Commission to a true value of service standard or to incorporate societal principals of ratemaking in the distributed renewable energy arena could be construed as setting a precedent for other value and societal considerations relating to other energy resources such as coal and natural gas.

In conclusion, utility rates are not the solution to addressing all societal cost or benefits relating to renewable energy adoption rather comprehensive public policies

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[27] https://www.tva.gov/Energy/Valley-Renewable-Energy/Distributed-Generation%E2%80%93Integrated-Value-Report

[28] Bonbright, James C., *Principles of Public Utility Rates* (Columbia Press, 1961)

such as tax laws, economic development incentives, or workforce training and education may be better served to work in combination with sound cost based ratemaking to accomplish this objective assuming that the objective itself is desirable.

VI. Avoided Cost Methodology Establishes a Foundation for Compensation

In establishing a conscious design for evaluating the compensation rates proposed under the Net Metering Act, a logical starting point would be to first assess the avoided costs of Kentucky's regulated electric utilities. In fact, absent a definition or prescribed methodology in the Net Metering Act, the avoided cost definition under PURPA provides a useful frame of reference, acknowledging that this definition is specific to compensation rates for Qualifying Facilities interconnecting under PURPA and is not necessarily an automatic substitute for the compensation rate specified under the Net Metering Act. However, it does provide a useful starting point for compensation rate discussions.

In Kentucky, PURPA is implanted via utility tariffs submitted under 807 KAR 5:054 for Small Power Production and Cogeneration facilities. A closer examination of the rates for the purchase of output from a qualifying facility provide interesting categorical considerations in avoided cost calculations and methodologies utilized. According to 807 KAR 5:054, rates or purchase of output in all cases shall be "just and reasonable to the electric customer of the utility, in the public interest and nondiscriminatory.....based on avoided costs which shall be subdivided into an energy component and a capacity component."[29]

[29] https://apps.legislature.ky.gov/law/kar/807/005/054.pdf

However, there are important factors outlined in Section 7 Subsection 5 regarding factors affecting rates for purchase for all qualifying facilities that could prove useful in assessing compensation rates under the Net Metering Act as these factors are currently allowed for consideration under PURPA. These factors are outlined as follows:

- Availability of capacity or energy during the system daily and seasonal peak,
- Ability to dispatch,
- Reliability,
- Terms of contract, duration of obligation, and termination requirements,
- Ability to coordinate scheduled outages,
- Usefulness of energy and capacity during system emergencies,
- Individual and aggregate value of energy and capacity,
- Shorter construction lead times associated with cogeneration and small power production,
- Ability of the electric utility to avoid costs due to deferral, cancellation, or downsizing of capacity additions, and reduction of fossil fuel use, and
- Savings or costs resulting from line losses that would not have existed in the absence of purchases from a qualifying facility.

Upon closer examination, many of these categories are similar to those outlined in the so-called VoS studies. The list also highlights the variability in avoided costs that may exist due to technology differences of the distributed renewable generation resource, the generation behavior of the resource, and the locational aspect of the resource on the utility's transmission and distribution system. A worthy question for the Commission is how Kentucky's regulated utility avoided costs methodologies compare against the list of factors in 807 KAR 5:054.

Kentucky is not alone in asking this question, avoided cost evaluations have been ongoing in a variety of states. For example, in 2017, the Michigan Public Service

Commission (MPSC) approved key aspects of the first update in 25 years of the approach utilities must take to determine avoided costs under the federal Public Utility Regulatory Policies Act (PURPA) of 1978.[30] The issue was also considered, in 2016, by the South Dakota legislature with the purpose of regulating how utilities statewide determine their avoided cost of generation.[31]

In another example, the Georgia PSC has established the avoided cost methodology for capacity and energy in Docket No.4822 and also required Georgia Power in Docket No. 16573 to file an annual Solar Avoided Cost Determination.[32] As a point of reference, the 2017 Avoided Cost and Solar Avoided Cost Projections can be found at the Georgia PSC.[33] The OEP notes that 807 KAR 5:054, requires all electric utilities with annual retail sales greater than 500 million kilowatt-hours to provide data to the Commission from which avoided costs may be derived not later than June 30, 1982, and not less often than every two (2) years thereafter unless otherwise determined by the Commission. In Section 5(2), each electric utility "shall maintain for public inspection" avoided cost information. The OEP encourages the Commission to examine the information submitted regarding utility avoided cost calculations per 807 KAR 5:054 and consider increasing the transparency and accessibility of the submitted avoided cost information to the public.

Admittedly, avoided costs are complex and recent changes in market conditions and the regulatory landscape have made long-run avoided costs much more difficult to

[30] https://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-413351--,00.html
[31] https://www.energymanagertoday.com/sd-legislation-lays-out-how-to-calculate-avoided-cost-of-generation-0122121/
[32] http://www.psc.state.ga.us/electric/GPC_%20QF_Fundamentals_Guide-PPT.pdf
[33] https://psc.ga.gov/search/facts-document/?documentId=170652

compute with an appropriate degree of precision or confidence. Indeed, PURPA implementation brings up a wide range of issues not appropriate for this proceeding, but nonetheless important for further consideration by the Commission as it relates to implementation of 807 KAR 5:054 in Kentucky. A replicable model for consideration is the 2016 FERC Technical Conference on the *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Docket No. AD16-16-000 where panelists discussed the various methods for calculating avoided cost, including the system average method, the use of natural gas prices and other fuel price indices in setting avoided cost, and setting avoided costs through auctions and/or requests for proposals.[34] Relevant to this topic, on September 19, 2019, FERC proposed to modernize its regulations governing small power producers and co-generators under PURPA, highlighting flexibility to states in setting energy rates.[35]

In summary, an evaluation of utility avoided cost calculation in relation to the factors outlined in 807 KAR 5:054 can be the foundation for establishing a framework for evaluating compensation rates proposed under the Net Metering Act. In the context of avoided costs, a key question before the Commission is if the retail rate accurately captures the cost of service that results from the benefits (avoided costs) of adding distributed generation? While the exported electricity's compensation rate is one issue for evaluation, another evaluation topic is whether this rate will be static or dynamic as well as the overall rate design employed by the utility in the proposed net metering tariff.

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[34] https://www.ferc.gov/CalendarFiles/20160304170725-AD16-16-000%20TC1.pdf
[35] https://www.ferc.gov/industries/electric/indus-act/reliability/09-19-19-E-1-fact-sheet.pdf

VII. Net Metering Act Implementation Issues

Guidance Document

The Commission, in 2008, issued *Interconnection and Net Metering Guidelines* per KRS 278.467 under Administrative Case 2008-00169. In 2019, with the Net Metering Act, questions remain on the obligation of the Commission to revise the *Interconnection and Net Metering Guidelines*, acknowledging that no further direction to the Commission or date revisions were included in the 2019 Net Metering Act. Since 2008, technological advancements in metering, billing, application processing, and changes to Institute for Electric and Electronic Engineers (IEEE), Underwriters Laboratories (UL), and National Electric Code (NEC) standards may necessitate revisions to the *Interconnection and Net Metering Guidelines.*

Specifically, the National Institute of Standards and Technology (NIST) has the responsibility of coordinating the development of an interoperability framework including model standards and protocols. Kentucky, with the Net Metering Act, has the opportunity to re-evaluate the interconnection guidelines in the context of the NIST Framework which is a "*compendium of interoperability standards that, in NIST's engineering judgment, are foundational to the smart grid.*"

The NIST Framework contains both standards and guidelines relating to smart metering, substation automation, electric vehicle grid integration, internet and wireless protocol usage, precision time synchronization, synchrophasors, customer energy usage (e.g., Green Button), cybersecurity, calendaring/scheduling models, and pricing models.[36] While not all standards are specific to net metering, the NIST Framework can assist the Commission on current and future decision making relating to interconnecting distributed energy resources.

Streamlining Interconnection Application Process

A survey of Kentucky's regulated utility websites highlights the difficulties in locating information on net metering. Often buried under multiple screens, located in categories such as rates, generating your own renewable energy, regulatory information, or under member services, finding net metering information can be difficult for the consumer. A potential area for improvement, KRS 278.467 states in (3) that:

> *"All retail electric suppliers shall make their net metering tariff and interconnection practices easily available to the public by posting the tariff and practices on their Web sites."*[37]

The OEP encourages the Commission to evaluate if regulated utility net metering tariffs and interconnection processes are "easily available" to the public.

Furthermore, when surveying the applications listed on the various utility websites, most applications are listed in combination with the tariff and in a portable document format, rendering them not conducive to electronic submittals. One exception is Duke Energy Kentucky that lists the application separately from the tariff and in a fillable portable document format. Duke Energy Kentucky also allows for submittal electronically via email.[38] Another example, Kentucky Power lists both a Kentucky

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[36] https://www.nist.gov/sites/default/files/documents/smartgrid/NIST-SP-1108r3.pdf
[37] https://apps.legislature.ky.gov/law/statutes/statute.aspx?id=14124
[38] https://www.duke-energy.com/home/products/renewable-energy/generate-your-own#tab-d009ae41-b4cf-4ec0-ba8f-082fce3f3a5c

Power Net Metering Customer Package that details the step by step process, a separate application that can be emailed, and a Guide for Interconnection.[39]

While some notable examples exist, one area that the OEP urges the Commission to evaluate is streamlining the application process and potentially reducing administrative costs to the utility, improving efficiency of the process, and increasing transparency for customers via submittal of net metering applications through an online secure portal, uploading of documents through the secure portal, sharing of customer usage information, generation production calculators, and online progress tracking of interconnection applications. The National Council of State Legislators provides an overview of state actions relating to reducing these "soft" costs.[40] Results from the National Renewable Energy Laboratory study illustrated that for a "sample across 87 utilities in 16 states, the median total project length for distributed PV systems installed between 2012 and 2014 was 53 business days (40–70 days between the 25th and 75th percentiles)".[41]

The OEP encourages the Commission to consider initiating an administrative case regarding updates to the *Interconnection and Net Metering Guidelines for Kentucky* in order to incorporate technical standard updates and explore options for streamlining the application and interconnection process for net metering customers.

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[39] https://www.kentuckypower.com/builders/GeneratingEquipment.aspx
[40] http://www.ncsl.org/research/energy/tackling-solar-energy-s-soft-costs.aspx
[41] https://www.nrel.gov/docs/fy15osti/63556.pdf

Hosting Capacity Analysis

In the Level 1 Application section of the *Interconnection and Net Metering Guidelines* for Kentucky, the following condition applies:

> *"For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices."*[42]

Given the advent of Hosting Capacity Analysis (HCA) where utilities can assess the distribution grid's ability to "host" additional DERs at specific locations without upgrades, the OEP recommends that the Commission consider HCA as an option for utilities as they integrate higher penetrations of DERs to the system, including those interconnected under net metering, and not rely on one standard percentage as the only measure of safety of the circuit. HCA is a tool where utilities and Commissions can assess the operational limits of the grid and can be deployed in the larger context of distribution planning.

HCA may not be relevant to utilities with low penetration and a standard percentage limit for circuits may suffice for protective measures; however, thinking to the future, HCA is an analytical tool that should be available for utilization in the context of DER interconnection procedures. In the end, the overall value and usefulness of HCA will depend on the process and framework that regulators employ to guide the development, design, and adaptation of the tool. The OEP recommends that the

[42] https://www.psc.ky.gov/agencies/psc/Industry/Electric/Final%20Net%20Metering-Interconnection%20Guidelines%201-8-09.pdf

Commission consult the resources below and consider incorporating HCA as an option in the Interconnection and Net Metering Guidelines.

- Interstate Renewable Energy Council's "*Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources*"[43] and the
- Electric Power Research Institute's "*Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity*"[44] reports for further assessment.

An administrative case considering updates to the *Interconnection and Net Metering Guidelines for Kentucky* could help clarify the use of hosting capacity analysis in assessing the impact of net metering customers on the transmission and distribution grid.

Netting Frequency

According to NREL, netting frequency is the time period under which distributed generation's electricity production and the customer's electricity consumption are summed and measured for billing purposes. With the deployment of advanced metering infrastructure, this netting frequency can occur instantaneously.[45] However, either through state legislative language or public utility commission orders, the movement beyond traditional retail rate net metering has required more specificity regarding netting frequency.

[43] https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/
[44] https://www.epri.com/#/pages/product/000000003002011009/?lang=en
[45] https://www.nrel.gov/docs/fy18osti/68469.pdf

Referring to the Net Metering Act, there is no direct mention of netting frequency. In KRS 278.465, "Net Metering" is defined as the difference between the dollar value of all electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period and priced as prescribed in KRS 278.466 and the dollar value of all electricity consumed by the eligible customer-generator over the same billing period and priced using the applicable tariff of the retail electric supplier.[46]

The use of the term "over a billing period" could be interpreted to mean that the netting frequency occurs at the end of the billing period. This is contrary to some stakeholders that would have the netting frequency occurring instantaneously "during the billing period". The OEP notes that while advanced metering has the capabilities to allow instantaneous netting, the current Net Metering Guidelines only require that the utility provide:

> *"net metering services, without any cost to the Customer for metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. This provision does not relieve the Customer of his or her responsibility to pay metering costs embedded in the utility's Commission-approved base rates. Any additional meter, meters, or distribution upgrades needed to monitor the flow in each direction shall be installed at the Customer's expense."*

Referring back to the Net Metering Act in KRS 278.466 (2), the requirement remains for metering:

> *"...a standard kilowatt-hour meter capable of registering the flow of electricity in two (2) directions. Any additional meter, meters, or distribution upgrades needed to monitor the flow in each direction shall be installed at the customer-generator's*

[46] https://apps.legislature.ky.gov/law/statutes/statute.aspx?id=49545

expense. If additional meters are installed, the net metering calculation shall yield the same result as when a single meter is used."

A simple bidirectional meters as indicated above is capable of spinning backward to record energy flowing from a customer generator's system to the utility grid. These basic meters are often referred to as "non-time-of-use meters" because they are incapable of recording when electricity was used: only how much was used. Time-of-use meters are more sophisticated, often digital, and can be referred to as advanced metering in that the meters can record both the amount of electricity used and when electricity is used.

As such, the Net Metering Act is silent on the use of advanced metering infrastructure for eligible customer generators and questions remain whether instantaneous netting <u>during</u> a billing cycle is allowed under the Net Metering Act definition. The OEP recommends that the Commission consider evaluating Net Metering tariff proposals in light of metering requirements including the billing details specified by the Utility regarding netting frequency. In addition, any clarification on metering and netting frequency could be done through a Commission revision to the *Net Metering and Interconnection Guidelines*.

The OEP notes that any advanced meter installed by a utility to allow for instantaneous netting of an eligible customer generator in a proposed tariff would be at the customer generator's expense. As an example of a comparable interpretation regarding netting over a billing period rather than instantons netting during a billing period, the OEP recommends reading the Minnesota PUC explanation of the use of the

Average Retail Utility Energy Rate.[47] An alternative example from Utah highlights the importance of specificity regarding netting frequency. In a stipulated settlement agreement under Docket Number: 14-035-114 with Rocky Mountain Power in 2017, the export credit is "measured and netted in fifteen (15) minute intervals".[48]

In addition to the other topics previously discussed, the OEP encourages the Commission to consider clarifying netting frequency as it pertains to billing procedures through an administrative case regarding updates to the *Interconnection and Net Metering Guidelines for Kentucky.*

Commercial and Residential Class Rate Design Impacts

The Net Metering Act increases the size of an eligible electric generating facility to that of forty-five kilowatts effective January 1, 2020. This increase allows for potential applications of projects into the commercial class of customers. As such, the class rate design of both the residential and commercial class of customers become important in evaluating any tariff proposals submitted under the Net Metering Act.

Recalling that one impetus for the Net Metering Act was intra-class cost shifting due to the fact that some utility fixed costs are embedded in the variable energy rate and are therefore not paid by the traditional net metering customer, the rate restructuring of aligning utility fixed costs with fixed rates within the residential customers class offers one solution to negating the intra-class cost shifting issue. Therefore, the OEP recommends that the Commission review each utility's residential

[47] https://mn.gov/puc/energy/distributed-energy/net-metering/
[48] https://pscdocs.utah.gov/electric/14docs/14035114/296270RMPSettleStip8-28-2017.pdf

rate design in the context of how this realignment may influence proposals under the Net Metering Act.

As an example, it is plausible, that as a utility proposes to move to straight fixed\variable rate structures then that utility would not need to revise the traditional net metering tariff because the retail compensation rate would be acceptable and reasonable. The same logic could be extended to commercial class customers. Any commercial class tariff that includes demand charges would therefore potentially negate any intra-class cost shifting and the retail rate net metering could be a reasonable compensation rate.

An issue before the Commission is that Net Metering Act proposals open up the potential for separate tariff proposals for residential and commercial class of customers in that the Net Metering Act does not specify applicability to only residential customers. While the compensation rate may be concluded to be the same for both classes for exported energy, the tariff design may be different based on the differences in the customer classes. The OEP recommends that the Commission review the February 21, 2018 *Report on the Michigan Public Service Commission Staff Study to Develop a Cost of Service Based Distributed Generation Program Tariff.*[49]

Data Needs for a Separate Customer Class

In the Net Metering Act, KRS 278.466 (5), each retail electric supplier is entitled to implement rates to recover all costs necessary to serve new net metering customers without regard for the rate structure of customers who are not eligible customer-

[49] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000016WftAAE

generators. This opens the door for separate rate classes for net metering customers. Theoretically, this option could entail a separate rate class for net metering residential and net metering commercial customers. The OEP notes that the development of separate classes for distributed generation customers is a distinct issue and in 2017, it was categorized as a trend by Utility Dive in the article "*In new trend, utilities propose separate rate classes for solar customers without rate increase*".[50] A key point from this article is the principle of gradualism where states are adopting smaller changes and obtaining more data from studies and pilots before shifting to widespread changes.

In states like Kentucky where the penetration of distributed generation sources is geographically dispersed and considered relatively low in comparison to the one percent (1%) cap referenced in KRS 278.466(1), the question of robustness of data to support a Cost of Service analysis for a separate rate class remains for the Commission. While a separate rate class may be indicated based on the assertion that a net metering customer utilizes the electrical system differently than other customers, utilities with advanced metering infrastructure with higher penetrations of distributed generation customers under net metering may be the only ones in a position to have the data requirements to substantiate the need for a separate rate class for net metering customers. The NARUC Manual is specific on this point,

> *"Use of data generated by AMI [Advanced Metering Infrastructure] can assist regulators to identify potential DER compensation methodologies, and have the*

[50] https://www.utilitydive.com/news/in-new-trend-utilities-propose-separate-rate-classes-for-solar-customers-w/508393/

data available to support the viability of the methodology as well as use it for settlement and compensation."[51]

Rate Design and Reasonableness May Depend on Penetration

As highlighted earlier, transforming net metering beyond the traditional retail rate design will likely be an ongoing process as costs and benefits may change based on the penetration of the distributed generation customer. The task ahead of the Commission may be one of a continuum of incrementalism and gradualism as penetration increases and data becomes more robust, transparent, and readily available. Again, the NARUC Manual provides guidance for the Commission in this area:

> *"Since all electric systems are affected by DER increases differently, before a jurisdiction embarks on the journey to implement substantive reforms due to the growth of DER adoption, it should look closely at data, analyses, and studies from its particular service area before any such actions are taken. The impacts that are occurring in one jurisdiction due to higher DER adoptions may not necessarily be the same for another that is experiencing similar DER adoption levels."*[52]

In fact, the NARUC Manual poses several questions to support the Commission's review. Below are a select few and the OEP encourages the Commission to consider these questions in light of compensation rates and rate designs submitted under the Net Metering Act:

- What is the current adoption level of net metering generation in the jurisdiction?
- Where is the net metering generation located?

[51] https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0
[52] https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

- Does the regulated utility have sufficient visibility into its distribution grid to monitor the impacts of distributed generation on its system?
- Does the regulator have sufficient information about rate and cost impacts from distributed generation on customer classes?
- Does the proposed net metering compensation mechanism accurately and objectively assess the costs, benefits, and risks of distributed generation?

In summary, the NARUC Manual provides guidance by asking "Does the regulator have access to the number of DER, different types of DER, and locations; number of customers who have adopted DER, the costs and benefits associated with those DER; a recent cost of service study; or, an indication or study showing any cost-shifting, by class, geography, or socio-economic?"

The OEP echoes the cautionary wording from the NARUC Manual and urges the Commission to consider both current and future forecasts of adoption\penetration levels when reviewing compensation rates and rate design proposals submitted under the Net Metering Act, especially in light of the one percent "cap" in KRS 278.466.

> *"Setting up an appropriate pricing and compensation structure should be done as soon as feasible, but there should not be so much urgency that the decision is made without all of the appropriate information. The results from such uninformed actions could be worse than no action at all. Adoption levels may, however, affect the amount and types of costs and benefits that accrue from DER installations. It is important to decide if different rate structures and compensation methodologies are appropriate for different stages of adoption, or if a single structure should be put in place that can deal with the differential impacts of various penetration levels."*

VIII. New Services and Revenue Opportunities from Distributed Generation

IEEE 1547-2018

On April 18, 2019, the OEP in cooperation with the Institute of Electrical and Electronics Engineers (IEEE) held a one day workshop for all stakeholders regarding the 2018 update to the IEEE 1547 Standard for Interconnection and Interoperability of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces. The IEEE 1547 is currently referenced in the Interconnection and Net Metering Guidelines for Kentucky as well as in interconnection agreements for Qualifying Facilities under PURPA tariffs. Sixty-five individuals attended with representation from Kentucky, Florida, and Michigan regulatory agencies as well as a number of electric cooperatives, contractors and installers, and local utilities.

The IEEE 1547 standard establishes criteria and requirements for the interconnection of distributed energy resources with the electric power systems and associated interfaces. The IEEE 1547 standard is a technical standard that details functional, uniform, and universal requirements that apply at the point of common coupling or the point of DER connection. The standard is not a design handbook, application guide, or interconnection agreements.

The updated standard (IEEE 1547-2018) requires DERs to provide an array of grid supportive functionality, including voltage and frequency ride-through, islanding, voltage and frequency regulation, as well as communications and control functionality. The requirements enable DERs to communicate with and receive signals from the grid. Using more sophisticated software infrastructure, these smart inverters can also be controlled and monitored remotely, allowing for curtailment functionality and further discussions around who should own inverters and appropriateness of utility control of customer-sited DERs.

According to the Interstate Renewable Energy Council, these capabilities will enable an increased amount of DERs that can be accommodated on the grid, allow for increased power quality for all customers, and ensure that DERs can be a reliable grid resource as penetration increases and the grid transforms. Although all DERs will be required to have these functionalities enabled, inverter-based DERs will utilize "smart inverters" to comply with the new standards.[53] Ultimately, these capabilities and increased functionality offer new opportunities to discuss how customers can be compensated for services being offered through DERs assuming that the services offered result in utility and grid net benefits.

In terms of what the IEEE 1547-2018 standard means for Kentucky, the April 2019 workshop in Kentucky was a starting point of the discussion. In contrast to earlier versions of the standard where many state regulatory commissions adopted the standard by incorporating it by reference, the new IEEE 1547-2018 lays out a set of options for deployment that may be selected based on system consideration and goals. Based on workshop presentations, stakeholders in Kentucky will require continued discussions on how default settings might be applied, or whether and when it's appropriate to deviate from default settings based on a DER project's level of interconnection review. Specifically, the Commission will be faced with considering:

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[53] https://irecusa.org/2018/07/smart-inverter-update-new-ieee-1547-standards-and-state-implementation-efforts/

- Appropriateness of actions to assign performance categories per DER technology and use cases.
- Appropriateness of actions to specify "preferred" utility required profiles for DER functional settings.
- Appropriateness of actions that specify certification for DER equipment and possibly verification for DER facilities.[54]

As an example from other states, the Michigan PSC on November 8, 2018 issued an order in Case No. U-20344 directing Commission Staff to initiate a stakeholder process with the purpose of gathering input to assist Commission Staff with updating the Commission's Electric Interconnection and Net Metering Standards. (R 460.601a – R 460.656). Specifically, the order directs Commission Staff to consider interconnection request procedures, timelines, and queue management; required interconnection studies; cost responsibility; safety and technical specifications. Furthermore, the order also states that the FERC small generator interconnection procedures, FERC Order 841 issued on February 15, 2018 related to energy storage facilities, microgrids, IEEE 1547-2018 standards, and best practices among states should be considered.[55] The OEP notes that state actions such as in Michigan and Minnesota[56] are tied to statewide interconnection standards and as noted earlier there are no statewide interconnections standards in Kentucky, only guidelines for interconnection under Net Metering.

[54] Presentation from April 18, 2019 Workshop, " Distributed Energy Resources and the Need for Updated Standard & Codes, Michael Coddington, National Renewable Energy Laboratory.

[55] https://www.michigan.gov/mpsc/0,9535,7-395--482687--,00.html

[56] https://mn.gov/puc/utilities/interconnection/

In 2006, the Commission considered whether to adopt federal standards set forth in the Energy Policy Act of 2005. The Act addressed a number of issues, including whether utilities should be required to offer optional rates that varied with the time of day, as well as the necessary advanced meters. The Commission chose not to adopt the standards, but required the five electric utilities with generating facilities in Kentucky to offer time-based rates to their largest customers. The Federal Energy Independence and Security Act of 2007 required the Commission to again consider the adoption of federal smart grid standards. The Commission, in October 2012, decided to defer a final decision on the federal standard and opened an administrative case that concluded in April of 2016. The Commission again decided against adopting uniform federal standards governing investments in smart grid infrastructure and the types of information provided to customers through smart grid technology.[57]

Based on developments such at the IEEE 1547-2018 update, FERC order 841 (discussed below), and updates to FERC Interconnection Agreements and Procedures since 2016, the OEP recommends that the Commission consider opening an administrative case regarding an evaluation of the interconnection requirements of DERs; review of utility interconnection requirements, process, and procedures; the need for additional standardization of interconnection agreements; and best practices from other states which could also involve updates to the *Interconnection and Net Metering Guidelines for Kentucky*. The OEP is also submitting for consideration two resources for review SEPA's *Distributed Solar Interconnection Challenges and Best Practices* report

[57] http://psc.ky.gov/agencies/psc/press/042016/0413_r01.pdf

and (2) SEPA's *Unlocking Advanced Inverter Functionality: Roadmap to a Future of Utility Engagement and Ownership.*

Aggregation of DERs and Wholesale Market Participation

In November of 2016, FERC issued a Notice of Proposed Rulemaking (NOPR) that required independent system operators (ISO) and regional transmission organizations (RTO) to establish market rules for energy storage and allow aggregated DERs to participate in wholesale markets. In February 2018, FERC addressed energy storage by issuing Order 841 and on April 11th and 12th, FERC held a technical conference to address the participation of DER aggregation in markets managed by independent system operator and regional transmission organization including the potential effects of DERs on the bulk power system. In May 2019, FERC denied rehearing requests and declined to adjust the timeframe for considering matters that affect DERs. While Order No. 841 addresses the participation model for non-aggregated electric storage resources participating directly in the RTO/ISO markets, Docket No. RM18-9-000 involves issues related to RTO/ISO market rules for distributed energy resources participating through aggregations.

The FERC NOPR and Order 841 omit important language adopted by FERC relating to demand response aggregations. That language specified that aggregation was only allowed with the authorization of the relevant retail regulatory authority, either the electric board for municipalities in Kentucky or the KY PSC for regulated electric utilities. It should be noted that the Federal Power Act preserves state and local regulatory authority over retail electricity sales and local distribution service.

As a reference, East Kentucky Power Cooperative, Inc. (EKPC) provided prepared statements regarding the aggregation of DERs wherein EKPC reiterated a FERC decision regarding the aggregation of energy efficiency resources. In that case, EKPC noted that FERC affirmed its prior decision that, in Kentucky, load seeking to participate in the PJM markets via any demand-side management programs requires prior KY PSC approval. FERC thus recognized that the KY PSC has jurisdiction over those resources, including energy efficiency resources. PJM has since filed a tariff change at FERC to implement FERC's upholding of the KY PSC's determination regarding EE resources.[58]

FERC Order 841 requires regional transmission organizations and independent system operators to enable storage resources, including those connected to distribution systems or behind the meter, to participate in the wholesale market, all but eliminating state regulatory authority. While it remains unclear if FERC will follow Order 841 framework for DER aggregation or adhere to previous decisions relating to aggregating demand response and energy efficiency, the key point is that FERC has signaled aggregation of DERs potentially provide services for compensation at the wholesale market level. In Kentucky that would translate into distributed generation resources like rooftop solar arrays under net metering being able to potentially be aggregated into a "virtual power plant" and compensated for wholesale market services and benefits.

Assuming penetration levels are sufficient for aggregation, there is a presumption that these resources provide services that result in benefits to the transmission grid for

[58] https://www.ferc.gov/CalendarFiles/20180411084435-Crews,%20East%20Kentucky%20Power%20Coop.pdf

compensation. Using the same logic, a question for consideration by the Commission regarding compensation rate is "Are there penetration levels where aggregation of DERs provide transmission and distribution level services and benefits that require compensation, knowing that IEEE 1547-2018 and Advanced Metering Infrastructure are instruments to unlock these potential services?" This question alone raises the issue of the appropriateness of compensation frameworks (rates and rate designs) that correspond to penetration levels and indicate that these frameworks will be an ongoing discussion as both adoption levels, technology, and actions at the federal level change.

IX. Resources for Consideration

The OEP is including the following resources not cited previously in these comments for consideration by the Commission and for inclusion in the record.

- American Public Power Association's "*Rate Design for Distributed Generation: Net Metering Alternatives*"
- The Law Offices of Carolyn Elefant "*Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and a Proposed Path for Reform*"
- Lawrence Berkeley National Laboratory's: " *Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment*"
- Lawrence Berkeley National Laboratory's "*Putting the Potential Rate Impacts of Distributed Solar into Context*"

- The National Regulatory Research Institute's "*Review of State Net Energy Metering and Successor Rate Designs*"
- The Regulatory Assistance Project's "*Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition*"
- The Regulatory Assistance Project's "*Smart Rate Design for a Smart Future*"
- The National Renewable Energy Laboratory's "*A Valuation Based Framework for Considering Distributed Generation Photovoltaic Tariff Design*"

X. Conclusions

The OEP again commends the Commission for its leadership in this important area and appreciates the opportunity to provide public comments in that regard. The past several years have witnessed a dramatic shift within the energy landscape of Kentucky and nationwide with one such topic being the evolution of net metering and growth of distributed generation.

It is the task of the Commission to establish some conscious design in determining the reasonableness of proposed net metering compensation rates and tariff designs moving forward. As stated earlier, utility rates are ineffective instruments for addressing societal cost or benefits. Comprehensive public policies working in combination with sound cost based ratemaking may be better served to accomplish the objective of supporting distributed renewable energy adoption, assuming the objective itself remains desirable by stakeholders.

Faced with the implementation of the Net Metering Act, the Commission faces three core questions:

1. How does the net metering compensation rate structure work together with PURPA tariffs to provide a comprehensive regulatory framework for interconnecting distributed renewable energy generation, while having the attributes of simplicity, understandability, public acceptability, and feasibility of application as well as freedom from controversies as to proper interpretation.
2. Does the current rate structure and\or proposed compensation rate structure accurately capture the cost of service that results from the costs and any corresponding benefits (avoided costs) of adding eligible customer generators to the system?
3. Are different rate structures and compensation methodologies appropriate for different stages of adoption, or is a single structure more appropriate to deal with the differential impacts of various penetration levels?

Any rate structure should also adhere to the eight attributes of sound rate structures identified by Bonbright.

The OEP encourages the Commission to take this opportunity to evaluate several implementation issues with the Net Metering Act including revising the *Interconnection and Net Metering Guidelines for Kentucky*, assessing the implementation of PURPA tariffs against any applicable FERC orders and 807 KAR 5:054, and examining avoided cost methodologies and requirements per 807 KAR 5:054.

The OEP recommends the Commission consider a robust stakeholder engagement process along with engaging experts in the field to facilitate greater understanding of these complex issues. Many of the issues highlighted involve the need for robust data collection and analysis to order for the Commission to make informed decisions as well as emphasizing the need for more staff training on specific technological or policy concepts. For Kentucky, learning from other state actions relating to net metering implementation is essential.

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