BEFORE THE PUBLIC SERVICE COMMISSION
OF THE COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) APPROVAL OF TARIFFS AND RIDERS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; (4) APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	Case No. 2020-00174

Direct Testimony of James M. Van Nostrand

On Behalf of Kentucky Solar Industries Association, Inc.

October 7, 2020

I. INTRODUCTION

Q. Please state your name, title and employer.

A. My name is James M. Van Nostrand. I am an Energy Policy Expert for EQ Research, a consulting firm based out of Cary, North Carolina. I am also a Professor of Law at the West Virginia University College of Law, where I teach energy and environmental law and Direct the Center for Energy and Sustainable Development.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of the Kentucky Solar Industries Association, Inc. ("KYSEIA"). Two of my colleagues at EQ Research, Justin Barnes and Benjamin D. Inskeep, are also presenting testimony on behalf of KYSEIA.

Q. Please state your educational and professional experience.

A. Exhibit JMV-1 sets forth my educational background and professional experience.

Q. How is the KYSEIA testimony organized?

A. My testimony provides background information regarding the issues in this proceeding, and summarizes the policy recommendations of the KYSEIA witnesses regarding net metering issues. In addition, my testimony addresses Kentucky Power's proposal regarding the compensation for Qualifying Facilities ("QFs") under its cogeneration and/or small power production tariff.

KYSEIA witness Justin Barnes provides a critical review of the various elements of Kentucky Power's NEM 2.0 proposal, and offers alternative designs for the Commission's consideration and a recommended approach that includes mandatory time-of-use rates.

KYSEIA witness Benjamin D. Inskeep provides a comprehensive examination of the approaches used by other states in addressing the issues faced by the Commission in this proceeding. The Commission in its December 18, 2019 Order in Case No. 2019-00256, *Electronic Consideration of the Implementation of the Net Metering Act*, observed that the initial proceedings to implement the amended Net Metering Act are "not ordinary matters," and stated that "it is obvious that other states and stakeholders have dealt with issues similar to those the Commission expects to be adjudicated in ratemaking proceedings under the Net Metering Act." With those statements by the Commission in mind, Mr. Inskeep's testimony includes a thorough review of actions taken by other states with respect to net metering policies, legacy rights, and related issues.

Q. Please summarize the KYSEIA testimony.

A. The KYSEIA testimony reaches the following conclusions and recommendations:

- The Commission should reject the Company's proposed N.M.S. II tariff. Kentucky Power has failed to demonstrate that the proposal meets a basic requirement of S.B. 100 dictating that the rates charged to distributed generation ("DG") customers recover only the costs associated with serving those DG customers, in the absence of DG customer load research and an accompanying cost of service study illustrating that current rates are not sufficient for this purpose.
- In the alternative, in the event the Commission determines that changes to the Company's net metering tariff are necessary, it should still decline to adopt the Company's specific proposal because it contains numerous structural flaws. A better approach would be to consider the options set forth in Mr. Barnes's testimony and take a forward-looking approach to DG tariff design with the objective of developing a durable framework and one or more tariff options that can made consistent across all utility service territories and can be adapted with minimal disruption for use after a utility reaches its net metering cap.
- The Company's COGEN/SPP tariffs should be modified to clearly specify that QFs have the option to receive compensation at the prevailing rates at the time the QF establishes a legally enforceable obligation ("LEO"), with the allowable duration set at a minimum of ten years in order to facilitate QF financing and create true ratepayer indifference by leveling the playing field between utility-owned and non-utility-owned generation.
- The Commission should adopt a 25-year Legacy period with respect to rate design, netting period, and compensation rate for customers taking service under any tariff approved in this proceeding to replace tariff N.M.S. I.
- Net metering customers, regardless of whether they are taking service under tariff N.M.S. I or a tariff approved in this proceeding to replace tariff N.M.S. I, should be allowed to maintain their Legacy Rights if they subsequently install a battery energy storage system ("BESS").

- Net metering customers should be allowed to expand the size of a Legacy net metering facility up to the customer's annual electricity usage or 45 kW, whichever is less, without forfeiting their respective Legacy Rights. Customers should also be allowed to replace components of a net metering system, such as solar panels, without forfeiting Legacy Rights, even if it results in modest increases in the total system capacity.

Q. How is your testimony organized?

A. The first part of my testimony focuses on the net metering issue, including a background discussion of S.B. 100, An Act Related to Net Metering ("S.B. 100" or the "Net Metering Act"), codified at Ky. Res. Stat. § 278.466, and the Commission's December 18, 2019 Order in Case No. 2019-00256. I then discuss Kentucky Power's net metering proposal, and offer a proposed framework for evaluating alternative approaches for net metering. I briefly discuss the experience from other states on this issue, with particular attention to the recent experience in Oklahoma under a similar legislative directive. The second part of my testimony discusses recent developments with respect to the determination of avoided costs under the Public Utility Regulatory Policies Act of 1978 ("PURPA)" as they relate to the Company's obligations with respect to QFs.

II. NET METERING

Q. Please describe the Net Metering Act.

A. The Net Metering Act, S.B. 100, was signed into law by then-Governor Matt Bevin on March 26, 2019, and is codified at Ky. Res. Stat. § 278.466. The Net Metering Act revised the compensation rate paid to net metered customers who start new net metering service as of the initial net metering order by the Commission in accordance with Ky. Res. Stat. § 278.466(3), effective as of January 1, 2020. Rather than valuing the electricity generated by a net metered customer that is fed back to the grid at the same per-kWh retail rate as that in the utility's tariff for electricity consumed by the net metered customer, the Net Metering Act specified that the compensation for production in excess of usage over a billing period, after the initial net metering order, "shall be in the form of a dollar-denominated bill credit," and gave the Commission "an integral role in determining the compensation rate for net metered customers." (Case No. 2019-00256, Order, p. 2)

Mr. Barnes's testimony discusses the portions of the Net Metering Act that are most relevant to Kentucky Power's N.M.S. II proposal in this proceeding.

The Net Metering Act also addressed the issue of transition for customers served under the existing net metering rules, by granting "Legacy Rights" for 25 years. According to the Net Metering Act:

> For an eligible electric generating facility in service prior to the effective date of the initial net metering order by the commission in accordance with subsection (3) of this section, the net metering tariff provisions in place when the eligible customer-generator began taking net metering service . . . shall remain in effect at those premises for a twenty-five (25) year period, regardless of whether the premises are sold or conveyed during that twenty-five (25) year period.

This provision is discussed in more detail in Mr. Inskeep's testimony.

Q. What did the Commission do in response to the Net Metering Act?

A. The Commission initiated an administrative proceeding, Case No. 2019-00256, to solicit comments from interested utilities, stakeholders and the general public for purposes of developing a record upon which the Commission could consider the issues of implementation of the Net Metering Act in subsequent ratemaking proceedings initiated by retail electric utilities. The record of Case No. 2019-00256 was directed to be incorporated by reference into all initial ratemaking proceedings initiated by retail electric utilities. This proceeding is the first such proceeding by a retail electric utility to implement the Net Metering Act.

Although the Commission did not make findings of fact or law regarding the implementation of the Net Metering Act, it committed to developing "a process that identifies known or reasonably expected measurable costs and benefits that can be factored into the ratemaking process, along with next best alternatives, based on the principle of most reasonable least-cost alternative, and opportunity costs." (Case No. 2019-00256, Order, p. 33)

Q. Please describe Kentucky Power's net metering proposal in this case.

A, Kentucky Power is proposing to close its current tariff N.M.S. I and replace it with tariff N.M.S. II for new net metering customers effective December 30, 2020. Mr. Barnes describes the Company's N.M.S. II proposal in more detail in his testimony. Under

Kentucky Power's proposal, its N.M.S. II tariff would take effect upon Commission approval and would be available only for new customer enrollment until the total generating capacity of net metering systems reaches one percent (1%) of its single hour peak load during the previous year. As discussed in Mr. Inskeep's testimony, the Company's proposal does not include any Legacy Rights for N.M.S. II customers.

Q. Do you have a recommended framework for analysis of the various net metering proposals in this proceeding?

A. Yes. As noted by the Commission in its December 2019 Order, the Net Metering Act assigns the Commission "an integral role in determining the compensation rate for net metered customers." Importantly, the Net Metering Act, at Ky. Res. Stat. § 278.466(5), preserves the ratemaking principle that rates be cost-based:

> "[E]ach retail electric supplier shall be entitled to implement rates to recovery from its eligible customer-generator all costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators."

As summarized in Mr. Barnes's testimony, this portion of the Net Metering Act requires that a utility demonstrate that (1) the rates offered to customer-generators are consistent with its costs to serve those customer-generators, and (2) the rate for exports properly reflects the value of exports to the grid.

The Net Metering Act also specifies that such cost-based rates are to "be set by the commission using the ratemaking processes under this chapter [KRS Chapter 278]." The Commission is thus charged with using its ratemaking expertise to equitably balance the diverse and conflicting interests of the stakeholders to this process. As observed by Chief Justice Rehnquist in *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 314 (1989), "economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result." In other words, ratemaking is not an exact science, but requires the agency to use its expertise to sort through the conflicting evidence offered by the parties to strike a balance that reasonably achieves the objectives of the Net Metering Act. In sorting through the evidence offered by the parties, of course, the utility still retains the burden of demonstrating that its proposal will result in fair, just and reasonable rates, as that essential element of the ratemaking process is unchanged by the Net Metering Act.

Q. Are there widely accepted ratemaking principles that should come into play?

A. Yes. Given the numerous occasions in which the Commission will be called upon to exercise its judgment as it balances the conflicting evidence offered by the stakeholders in this proceeding, it is worth recalling *The Principles of Public Utility Rates* articulated by James Bonbright in 1961,[1] which was referred to recently as a "profoundly influential treatise."[2] Bonbright articulated eight desirable attributes of a rate structure:[3]

1. "The related 'practical' attributes of simplicity, understandability. public acceptability and feasibility of application."
2. "Freedom from controversies as to proper interpretation."
3. "Effectiveness in yielding total revenue requirements under the fair return standard."
4. "Revenue stability from year to year."
5. "Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers" (commonly referred to as "gradualism").
6. "Fairness of the rates in apportioning the total costs of service among different consumers."
7. "Avoidance of 'undue discrimination' in rate relationships."
8. "Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use." (This "economic efficiency" attribute relates to one of the "primary objectives" identified by Bonbright: "the optimum-use or consumer rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received.")[4]

Although the principles themselves are generally non-controversial, they frequently conflict with one another and present a need for subjective judgments as to interpretation

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[1] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press (1st Ed., 1961).
[2] Karl R. Rábago and Radina Valova, *Revisiting Bonbright's Principles of Public Utility Rates in a DER World*, THE ELECTRICITY JOURNAL 31 (2018) 9-13.
[3] Bonbright, *Principles of Public Utility Rates* at 291.
[4] *Id*. at 292.

(e.g., the practical meaning of “stability" or “gradualism”) and the relative weighting each attribute should receive.

Q. Are there certain principles that you believe should be given greater weight in this proceeding?

A. Yes. Gradualism is particularly important in this proceeding. Determining the “dollar-denominated bill credit” need not be a radical departure from the existing practice of tying the compensation to customer-generators to the retail rate, if the Commission strikes a fair balance among the interests of the various stakeholders in this proceeding. Along the same lines, the reference to the revenue requirement (or “financial-need objective,” according to Bonbright) is another important consideration. But it is not only the utility’s revenue requirement that is at issue in this proceeding; utilities are not the only stakeholders in this proceeding with “skin in the game.” As stated in a recent article regarding the current applicability of Bonbright principles:

> “Customers, in their own right and through non-utility parties, are making their own investments in electric service provision—they have their own ‘revenue requirements.’ Services are no longer only provided by the electric utility so the scope of inquiry regarding economic efficiency must countenance a much broader review of costs and benefits, over both the short and long term.”[5]

The Commission’s determination of the “dollar-denominated bill credit” must thus consider not only the financial needs of the utility, but also the economic impact on all market participants, including customer-generators and third-party providers.

Q. As the Commission exercises its judgement to resolve the diverse and conflicting testimony from the stakeholders in this proceeding, what is at stake?

A. The actions the Commission takes in this proceeding will send a strong signal as to whether there is a future for solar in Kentucky. The point of my reference to Chief Justice’s Rehnquist’s statement from the *Duquesne v. Barasch* case above—that “economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result”—is to emphasize that there is not a single number that precisely

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[5] Rábago and Valova, *Revisiting Bonbright’s Principles of Public Utility Rates in a DER World*, THE ELECTRICITY JOURNAL 31 at 10.

captures the costs to serve customer-generators or that reflects the value of exports to the grid. Rather, there is a range of numbers that will be supported by the evidence in this case, and whether the Commission chooses a number at one end of the range or the other will have a significant impact on the prospects for development of a robust solar market in Kentucky. The stakes are high, given the potential for jobs and economic activity in Kentucky, as shown in the chart below which compares solar development in Kentucky versus the surrounding states:

State	MW Solar	No. of Installations	Solar Jobs
Kentucky	54.50	1,202	1,362
North Carolina	6,451.05	17,788	6,617
Tennessee	350.93	2,561	4,194
Virginia	1,099.65	12,586	4,489
Illinois	307.62	17,113	5,513
Indiana	454.82	3,621	3,600
Ohio	288.37	6,443	7,282
West Virginia	10.22	325	340

Source: Solar Energy Industries Association, *Solar State by State*, available at https://www.seia.org/states-map

The difference in jobs and solar generation cannot be explained solely by differences in solar potential (i.e., solar intensity); rather, it is the difference in state policies that support solar development and, just as important, the judgements exercised by state regulators in striking a balance when weighing the conflicting testimony and arriving at an estimate of "costs" and "values." Landing on a number at the lower end of the range of "values" for the contribution of DERs to the grid, for example, or at the higher end of the "costs" to serve customer-generators, will have consequences on the development of solar in Kentucky. The decisions the Commission makes in this proceeding, and in subsequent proceedings involving other Kentucky utilities, will to a large extent determine whether Kentucky is more like West Virginia—the state with which I am most familiar with respect to energy policies—or North Carolina, or Virginia. Its decisions are particularly important given recent actions at the Federal Energy Regulatory Commission ("FERC") that create new opportunities for DERs to participate in the wholesale markets.

Q. What is the recent action at FERC to which you are referring?

A. On September 17, 2020, FERC issued its Order No. 2222, which opens up tremendous opportunities for DERs to participate in the wholesale energy markets. Order No. 2222 adopts rules designed to remove barriers to DER participation in the organized markets for electric energy, capacity, and ancillary services operated by Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"). The Order requires regional grid operators to revise their tariffs to establish DER aggregators as a type of market participant, which would allow them to register their resources under one or more participation models that accommodate the physical and operational characteristics of those resources. FERC Chairman Neil Chatterjee cited projections that indicate between 65 gigawatts to more than 380 gigawatts of DERs could be added to the country's power grids over the next four years.[6] Whether that substantial growth in the DER industry, and the associated jobs, is developed in Kentucky will depend in large part on the decisions the Commission makes in this proceeding and in subsequent utility filings.

Q. How have other states approached the transition away from retail rate-based net metering?

A. Kentucky is not the first state to pursue refinement of its DG and net metering laws. Mr. Inskeep's Exhibit BDI-2 identifies that states that have approved modified net metering policies or established a process for creating modified net metering or a net metering successor policy. It is important to reiterate that the vast majority of states continue to offer net metering to customers. Exhibit BDI-2 shows that five states (Arizona, Hawaii, Louisiana, Michigan, Utah) have adopted net billing arrangements to replace an existing net metering policy. At least 10 states (Arkansas, California, Connecticut, Illinois, Indiana, Iowa, Kentucky, New Hampshire, New York, South Carolina) have articulated a process by which a modified net metering policy or net metering successor policy can be

[6] Remarks of Chairman Neil Chatterjee on Order 2222, September 22, 2020, available at https://www.ferc.gov/news-events/news/remarks-chairman-neil-chatterjee-order-2222

established, although the extent of the modifications remains largely unknown for most of these states. Mr. Inskeep's testimony includes the following observations:

- Kentucky Power has a comparatively low solar DG penetration relative to most IOUs in states identified in Exhibit BDI-2 that have established modified net metering policies or adopted net metering successor policies.
- Kentucky's 45 kilowatt (kW) maximum system size for net metering system eligibility is among the most restrictive.
- Third, Kentucky's 1% net metering cap is smaller than the net metering cap in most states.
- Finally, most states have maintained net metering policies until after their net metering cap has been reached, and even then, the cap is often extended.

Q. What are some of the key take-aways from these actions in other states?

A. Examples from other states illustrate the options available and how regulators have balanced competing goals in ratemaking. State consideration of changes has arisen in varying contexts, often with different underlying statutory directives. In terms of lessons learned, it seems clear that long-running evolving efforts and substantial study are necessary to reliably implement a true cost and benefits equilibrium framework, including targeted load research and full evaluation of costs and benefits. Because of this need for additional information and further study, regulators have generally been cautious and measured with their adoption of changes. In numerous cases, the absence of the necessary supporting evidence has prompted rejection followed by further consideration as more information is gathered. Another general observation concerns the treatment of Legacy Rights, which Mr. Inskeep discusses in his testimony. Based on his analysis, it appears that granting Legacy Rights for both existing net metering customers (N.M.S. 1) and new customers under the successor tariff (N.M.S. II) is nearly universal.

Q. Is there any particular precedent from other states that might provide some guidance to the Commission?

A. A relatively recent decision in Oklahoma involving another AEP affiliate, Oklahoma Gas & Electric ("OG&E"), comes to mind. In 2014, the Oklahoma legislature enacted S.B. 1456, which generally shares common ground and directives with S.B. 100 inasmuch as it (a) provides for rates based on the full cost to serve DG customers, (b) prohibits DG customers from being subsidized by customers in the same class, (c) refers to fixed charges as a means of addressing potential subsidies (i.e., referring to a fixed charge as "reflecting the actual fixed costs of the retail electric supplier"), and (d) provides for the subsidy prohibition to take effect on the effective date of the law.

Q. What action did the Oklahoma Corporation Commission ("OCC") take?

A. When the OCC first considered the issue of potential cross-subsidization, it found that while OG&E's existing tariffs "could" create the opportunity for cross-subsidies that benefit DG customers, it was not persuaded that OG&E had demonstrated the existence of a subsidy based on the record in the case. The OCC further stated that it was not convinced that OG&E's proposed DG tariffs—which included the imposition of demand charges—would result in charging DG customers "only the amount required to recover the full costs necessary" to serve them. The issue was referred to OG&E's then-pending rate case and, as part of the subsequent stipulation settling the case, the demand charges proposed by OG&E were removed.

Q. What do you conclude from this precedent?

A. The precedent illustrates my point that the utility has the burden of proof to demonstrate the reasonableness of its rate proposal. In the absence of Kentucky Power sustaining that burden with respect to its proposed N.M.S. II rate, the existing N.M.S. I rate remains in effect. In other words, the filed rate as of January 1, 2020 remains the applicable rate until such time as the Commission enters an initial net metering order changing the rate. The Commission has the necessary flexibility to consider alternatives, of course, and weigh their virtues in light of the amount of cost-of-service evidence presented (or, in Kentucky Power's case, the lack of such evidence). Given the very small rates of penetration for DG in Kentucky, as noted in Mr. Inskeep's testimony, the Commission would have a basis for concluding that both Kentucky Power and its ratepayers would be effectively financially indifferent regardless of the outcome. In the event the Commission wishes to consider alternative approaches to Kentucky Power's proposal, Mr. Barnes's testimony offers several alternatives for the Commission's consideration.

III. ESTIMATING AVOIDED COSTS

Q. What is the issue with respect to the calculation of avoided costs?

A. The issue is the Company's compliance with its obligations under PURPA to purchase the output from QFs at avoided costs, and arises in three respects in Mr. Barnes's testimony. First, he discusses the flaws in the Company's calculation of avoided costs for purposes of developing the rates in its proposed N.M.S. II tariff. Second, Mr. Barnes discusses the development of a successor tariff for customer-generators that would extend beyond the statutory net metering cap (when "the cumulative generating capacity of net metering systems reaches one percent (1%) of a supplier's single hour peak load during a calendar year," according to Ky. Rev. Stat. § 278.466(1)). Under the proposal discussed by Mr. Barnes, net exports by customer-generators would be purchased by Kentucky Power at a rate equal to its avoided costs, consistent with the utility's obligations under PURPA to purchase energy and capacity from QFs at rates consistent with its avoided costs. Third, Mr. Barnes discusses whether the Company's COGEN/SPP [cogeneration and small power production] tariffs comply with PURPA, both as to the availability of a long-term contract and the capacity rate proposed by the Company.

Q. Please explain how PURPA comes into play in this case.

A. PURPA was enacted in 1978 to encourage the development of non-utility generation and, more specifically, cogeneration and small power production facilities. Section 210(a) of PURPA directed FERC to adopt rules that it determines necessary to encourage the development of qualifying small power production facilities and cogeneration facilities. Those rules were adopted in 1980, and have remained largely untouched until July of this year when FERC issued Order No. 872, which amended the rules in some important respects. Section 210(f) of PURPA also required the state regulatory authority with jurisdiction over electric utilities to implement the FERC rules. In response, the Commission adopted the rules codified at 807 Ky. Admin. Regs. 5:054, which largely mirror the rules adopted by FERC in 1980.

As noted above, PURPA generally requires an electric utility to purchase the output from QFs at the utility's avoided cost, which is defined in Section 1(1) of 807 KAR 5:054 as the "incremental costs to an electric utility of electric energy or capacity or both which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source." On June 28, 1984, the Commission issued an Order in Case No. 8566, *Setting Rates and Terms and Conditions of Purchase of Electric Power from Small Power Producers and Cogenerators by Regulated Electric Utilities,* providing guidance to the electric utilities operating in Kentucky about the Commission's practices in implementing PURPA, including the methods for determining the rates to by paid by each utility to QFs for avoided capacity and energy. The utilities were directed to base their capacity payments "on the potential savings (avoided capacity costs) which would result from deferral, downsizing or cancellation of power plants or capacity purchases within the utility's planning horizon." (Case No. 8566, Order, p. 4) With respect to avoided energy costs, the Order states that such rates "would be equal to the costs of operating the most expensive unit on line in the relevant time period." (Case No. 8566, Order, p. 24)

Q. What is the overall objective of PURPA?

A. The basic framework for PURPA centers on the idea that ratepayers should be indifferent to utility-owned vs. non-utility-owned generation assets. True indifference requires that the methods used to evaluate the "value" of a generation asset to ratepayers are the same for utility-owned and non-utility-owned assets. If the utility recognizes the need for additional capacity in its long-term planning and therefore assigns a capacity value to utility-owned resources, that same capacity value should apply when valuing the contributions of non-utility generation, including DG and other QF resources.

Q. How those principles apply in this case?

A. As Mr. Barnes discusses in his testimony, he takes issue with the Company's starting point in calculating avoided capacity costs in its N.M.S. II rate proposal.

Q. How does FERC's Order No. 742 affect the issues in this proceeding?

A. FERC's July 16, 2020 order affirms the considerable deference accorded to state utility commissions in the administration of PURPA and the determination of avoided costs. Most notably, the Order grants states the discretion to limit the pricing options available to QFs. FERC regulations have long given QFs the right to elect to deliver power "as available" or over a specified future term / contract period and to fix the avoided cost rates for both capacity and energy either at the time the legally enforceable obligation ("LEO") is established or at the time power is delivered. Order No. 742 allows states to eliminate—if they so choose, in the exercise of the wide discretion accorded them under PURPA—the requirement that a utility must afford a QF the option to enter a contract at a rate for energy that is either fixed for the duration of the contract or determined at the outset—e.g., based on a forward curve reflecting estimated prices over the term of the contract.[7] Order No. 742 also provides some guidance to states on the determination of avoided energy costs; it establishes a rebuttable presumption, rather than a per se rule, that locational marginal prices ("LMPs") may reflect a purchasing electric utility's avoided energy costs.[8]

Q. Do these changes in FERC's PURPA rules apply in this proceeding?

A. No. Order No. 742 does nothing to change the wide latitude that state regulatory commissions have in determining avoided costs and in establishing the terms and conditions for QF contracts. Moreover, the regulations adopted by the Commission at 807 KAR 5:054 remain in place until such time as the Commission takes action in a rulemaking to exercise the additional flexibility granted to it by FERC under Order No. 742.

Q. What is KYSEIA recommending with respect to the PURPA-related issued in this proceeding?

A. As stated in Mr. Barnes's testimony, KYSEIA recommends that Kentucky Power's COGEN/SPP tariffs be revised to clearly specify that QFs may seek a contract with pricing based on rates at the time of the establishment of a legally enforceable obligation, and specify the length of time that a QF make provide energy and capacity under a locked-in rate. As stated in Mr. Barnes's testimony, the Company's calculation of avoided capacity costs should be revised to use a 20-year useful life in place of a 40-year useful life, and a capital cost of at least $799/kW in place of $700/kW. Both of these recommendations are based on assumptions used in similar calculations performed by other well-respected sources of this type of information.

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[7] Final Rule, 172 FERC ¶ 61,041 at p. 253.
[8] *Id.*, pp. 151, 189, 211.

IV. CONCLUSIONS

Q. Please summarize KYSEIA's recommendations.

A. KYSEIA's testimony includes the following recommendations:

- The Commission should reject the Company's proposed N.M.S. II tariff based on the record in this proceeding. The Commission should direct that future applications for modifying DG rates and net metering tariffs be supported by the load research and complete cost of service analyses.
- The Company's COGEN/SPP tariffs should be modified to clearly specify that QFs have the option to receive compensation at the prevailing rates at the time the QF establishes a legally enforceable obligation ("LEO"), with the allowable duration set at a minimum of ten years.
- The Commission should adopt a 25-year Legacy period with respect to rate design, netting period, and compensation rate for customers taking service under any tariff approved in this proceeding to replace tariff N.M.S. I.
- Net metering customers, regardless of whether they are taking service under tariff N.M.S. I or a tariff approved in this proceeding to replace tariff N.M.S. I, should be allowed to maintain their Legacy Rights if they subsequently install a BESS.
- Net metering customers should be allowed to expand the size of a Legacy net metering facility up to the customer's annual electricity usage or 45 kW, whichever is less, without forfeiting their respective Legacy Rights. Customers should also be allowed to replace components of a net metering system, such as solar panels, without forfeiting Legacy Rights, even if it results in modest increases in the total system capacity.

Q. Does this conclude your testimony?

A. Yes.