COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

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| ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT | ) | CASE NO. 2020-00349 |
| ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT | ) | CASE NO. 2020-00350 |

**KENTUCKY SOLAR INDUSTRIES ASSOCIATION, INC.**
**JOINT POST-HEARING MEMORANDUM BRIEF**

Comes now the Kentucky Solar Industries Association, Inc. (KYSEIA), by and through counsel, and, pursuant to the Commission's August 19, 2021, Order, files this Joint Post-Hearing Brief. The Commission should deny the rates and changes proposed by Kentucky Utilities Company's ("KU") and Louisville Gas and Electric Company's ("LG&E) (collectively "Companies") for qualifying facilities and net metering service and set rates consistent with the recommendations in this Memorandum Brief. KYSEIA also requests a monthly netting period.

## I. KYSEIA'S PROPOSED AVOIDED COST CALCULATIONS FOR QUALIFYING FACILITIES' RATES COMPLY WITH KENTUCKY AND FEDERAL QUALIFYING FACILITIES' STATUTES AND REGULATIONS.[1]

### A. FEDERAL STATUTES AND REGULATIONS

The basic purpose of § 210 of PURPA is to "increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels."[2] Congress believed that "increased use of these sources of energy would reduce the demand for traditional fossil fuels," and it recognized that electric utilities had traditionally been "reluctant to purchase power from, and to sell power to, the nontraditional facilities."[3] Section 210(a) directs FERC, in consultation with state commissions to promulgate "such rules as it determines necessary to encourage cogeneration and small power production," including rules requiring utilities to offer to sell electricity to, and purchase electricity from, qualifying cogeneration and small power production facilities.[4]

Section 210(a) of PURPA imposes a mandatory purchase obligation on utilities.[5] Those purchases must be at rates that are (1) just and reasonable to the electric consumers and in the public interest, (2) not discriminatory against QFs, and (3) not in excess of the incremental cost to the electric utility of alternative electric energy.[6] Section 210(d) defines "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, but for

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[1] In its August 9, 2021, Order in these proceedings, the Commission requested that, in any briefs filed, "the parties address how their own proposed avoided cost calculations for qualifying facilities' rates comply with Kentucky and federal qualifying facilities' statutes and regulations."

[2] *American Paper Institute, Inc. v. American Elec. Power Service Corp*., 461 U.S. 402, 417 (1983) citing *F.E.R.C. v. Mississippi*, 456 U.S. 742, 751 (1982).

[3] *Id*.

[4] *Id*.

[5] PURPA, § 210(a), 16 U.S.C. § 824a-3(a).

[6] PURPA, § 210(b), 16 U.S.C. § 824a-3(b). *See also American Paper Institute, Inc*. at 405.

the purchase from [the QF], such utility would generate or purchase from another source."[7] To that end, FERC promulgated regulations outlining that utilities are obligated to purchase energy and capacity from QFs at the utility's full "avoided cost."[8] "Each electric utility shall purchase, in accordance with § 292.304, ... any energy and capacity which is made available from a qualifying facility..."[9] The rates for such purchases shall: (1) be just and reasonable to the electric consumer of the electric utility and in the public interest; and (2) not discriminate against qualifying cogeneration and small power production facilities.[10] "Avoided costs" is defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility…such utility would generate itself or purchase from another source."[11]

FERC's PURPA implementing regulations also establish different factors to determine QF rates.[12] For as-available QF energy sales, these <u>may</u> include using: (1) the Location Marginal Price (LMP) for in-market sales; (2) a Competitive Price (Market Hub Price or Combined Cycle Price) for outside market sales; or (3) a Competitive Solicitation Price.[13] The Commission may also establish rates for purchases of energy from QFs based on a utility's LMP calculated by an RTO[14] or a utility's applicable competitive price.[15] The Commission may also establish rates for

[7] PURPA, § 210(d), 16 U.S.C. § 824a-3(d).
[8] *Id.* § 292.303–304.
[9] *Id.* § 292.303(a) (2010).
[10] *Id.* § 292.304(a)(1) (2010).
[11] *Id.* § 292.101(b)(6) (2010).
[12] *Id.* § 292.304.
[13] *Id.* § 292.304(b).
[14] These include the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), ISO New England Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), Electric Reliability Council of Texas (ERCOT), California Independent System Operator (CISO,) and Southwest Power Pool, Inc. (SPP).
[15] 18 C.F.R. § 292.304(b)(6)-(7).

purchases of energy and/or capacity from a qualifying facility based on a Competitive Solicitation Price. Standard rates are required for QFs with a design capacity of 100 kW or less, but may be required for QFs with a design capacity of more than 100 kW or less.[16] These standard rates must be consistent with the other rules of the section and may differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies.[17]

To the extent that a Commission does not determine a QF energy or capacity rate based on the above prices, the Commission can, to the extent practicable, consider the following in determining rates for a QF:

(1) avoided costs data provided by a utility pursuant to § 292.302(b);

(2) the availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

   (a) The ability of the electric utility to dispatch the qualifying facility;

   (b) The expected or demonstrated reliability of the qualifying facility;

   (c) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non compliance;

   (d) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the electric utility's facilities;

   (e) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

   (f) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

   (g) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived from the avoided costs data provided by a utility pursuant to § 292.302(b), to

[16] *Id*. § 292.304(c)(2).
[17] *Id*. § 292.304(c)(2)(i)-(ii).

the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.[18]

However, the Commission is allowed a wide degree of latitude in implementating Section 210 of PURPA and the above factors in determining avoided costs.[19] For example, FERC has interpreted avoided costs to allow for verifiable avoided environmental compliance costs.[20] "The determinations that a state commission makes to implement the rate provisions of section 210 of PURPA are by their nature fact-specific and include consideration of many factors, and [FERC is] reluctant to second guess the state commission's determinations…our regulations thus provide state commissions with guidelines on factors to be taken into account, 'to the extent practicable,' in determining a utility's avoided cost of acquiring the next unit of generation.[21]

### B. State Statutes and Regulations

As noted by the Commission, "PURPA is a 'program of cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs.'"[22] The Commission

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[18] *Id*. § 292.304(e).
[19] *S. Cal. Edison Co. P. Gas and Electric Co. San Diego Gas & Electric Co*., 133 FERC ¶ 61,059, 61,070 (Oct. 21, 2010).
[20] *S. Cal. Edison Co. P. Gas and Electric Co. San Diego Gas & Electric Co*., 133 FERC ¶ 61,059, ¶ 62,080 (2010).
[21] *S. Cal. Edison Co. P. Gas and Electric Co. San Diego Gas & Electric Co*., 133 FERC ¶ 61,059, 61,070 *citing* 18 C.F.R. § 292.304(e) (2010). *See also Mississippi* at 751.
[22] Case No. 2020-00174, *In the Matter of: Electronic Application of Kentucky Power Company for (1) 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 Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief*, (Ky P.S.C. Jan. 13, 2021), Order at 99 (hereinafter "Case No. 2020-00174).

promulgated 807 KAR 5:054 to comply with Section 210(f) of PURPA, which required the Commission to implement rules adopted by the Federal Energy Regulatory Commission (FERC) to encourage cogeneration and small power production.[23] "These rules require, *inter alia*, electric utilities to sell electricity to qualifying cogeneration and small power production facilities and to purchase electricity from such facilities."[24]

Mirroring FERC's regulations, the Commission defines "avoided costs" 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."[25] Section 7 of 807 KAR 5:054 gives QFs the option of either: (a) Using output of the qualifying facility to supply their power requirements and selling their surplus; or (b) simultaneously selling their entire output to the interconnecting utility while purchasing their own requirements from that utility.[26] Each electric utility must prepare standard rates for purchases from qualifying facilities with a design capacity of 100 kW or less.[27] For QFs of 100 kW or less, the rates "shall be just and reasonable to the electric customer of the utility, in the public interest, and nondiscriminatory.[28] The rates shall be based on avoided costs, taking into account the factors listed in subsection (5)(a) of Section 7 (see below), and shall be subdivided into an energy component and a capacity component.[29] Rates offered on an "as available" basis shall be based on the purchasing utility's avoided energy costs estimated at time of delivery.[30] Rates offered on all

[23] Case No. 2020-00134, *In the Matter of: Electronic Investigation of Kentucky Power Company's Deviation from 807 KAR 5:054, Sections 5(1)(A) and (2)*, (Ky P.S.C. Apr. 28, 2020), Order at 2.
[24] *Id*.
[25] 807 KAR 5:054, Section 1 (1).
[26] *Id*., Section 7 (1).
[27] *Id*., Section 7 (2).
[28] *Id*.
[29] *Id*.
[30] *Id*., Section 7 (2)(a).

legally enforceable obligations shall be based at the option of the qualifying facility on either avoided costs at the time of delivery or avoided costs at the time the legally enforceable obligation is incurred.[31] The capacity component shall be based on supply characteristics of qualifying facilities, and the aggregate capacity value of all 100 kW or less facilities which supply power on a legally enforceable basis.[32] Electric utilities are required to design and offer a standard contract to qualifying facilities with a design capacity of 100 kilowatts or less and is subject to commission approval.[33]

An electric utility must provide a standard rate schedule for QFs with design capacity over 100 kW.[34] The rate schedule is based on avoided costs, which must also be subdivided into an energy component and a capacity component.[35] These rates are only used as the basis for negotiating a final purchase rate with qualifying facilities after considering the factors listed in subsection (5)(a) of Section 7 (see *infra*).[36] Negotiated rates must be just and reasonable to the electric customer of the utility, in the public interest, and nondiscriminatory.[37] If the electric utility and qualifying facility cannot agree on the purchase rate, then the Commission shall determine the rate after a hearing.[38] Rates offered on an "as available" basis for QFs over 100 kW must also be based on the purchasing utility's avoided costs estimated at time of delivery, and rates for energy or capacity or both offered on a legally enforceable basis shall be based at the option of the QF on

[31] *Id.*, Section 7 (2)(b).
[32] *Id.*
[33] *Id.*, Section 7 (3).
[34] *Id.*, Section 7 (4).
[35] *Id.*
[36] *Id.*
[37] *Id.*
[38] *Id.*

either avoided costs at the time of delivery or avoided costs at the time the legally enforceable obligation is incurred.[39]

As noted above, the Commission also promulgated several factors to take into consideration when determining rates for all QFs. These include:

(a) Availability of capacity or energy from a qualifying facility during the system daily and seasonal peak. The utility should consider for each qualifying facility the ability to dispatch, reliability, terms of contract, duration of obligation, termination requirements, ability to coordinate scheduled outages, usefulness of energy and capacity during system emergencies, individual and aggregate value of energy and capacity, and shorter construction lead times associated with cogeneration and small power production.

(b) Ability of the electric utility to avoid costs due to deferral, cancellation, or downsizing of capacity additions, and reduction of fossil fuel use.

(c) Savings or costs resulting from line losses that would not have existed in the absence of purchases from a qualifying facility.[40]

Thus, the Commission is given discretion to determine the QF rates based on the consideration of factors promulgated by both FERC and the Commission as long as those rates are in line with the regulations defining "avoided costs," and as long as the rates are just and reasonable to the electric consumer of the electric utility and in the public interest and do not discriminate against qualifying cogeneration and small power production facilities, all while taking into account the purpose of PURPA to "increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels."[41]

With this framework in mind, states have employed several different methodologies for calculating proper compensation for power purchased from QFs. Both the "Proxy Method" and

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[39] *Id.*, Section 7 (1)(a)-(b).
[40] *Id.*, Section 5.

[41] *American Paper Institute, Inc. v. American Elec. Power Service Corp.*, 461 U.S. 402, 417 (1983).

"Integrated Resource Planning Based Methodology" were employed by KYSEIA in its testimony and proposals, and are well-recognized methodologies for calculating proper compensation for power purchased from QFs.[42]

### C. KYSEIA'S QF TARIFF RECOMMENDATIONS

Prior to this case, the Commission most recently considered proposed QF rates in the Kentucky Power rate case, Case No. 2020-00174.[43] KYSEIA was granted full intervention in that case and criticized Kentucky Power's QF rates proposal for not being fair, just and reasonable, or non-discriminatory. Ultimately, the Commission used its discretion to approve a rate that allowed for (1) an avoided energy cost rate based on the variable LMP at the time of delivery; (2) an avoided capacity cost rate based on the zonal net CONE for the delivery years that have an established CONE at the time of the contract and the last known net CONE for the remainder of the term; (3) a QF to request that avoided cost rates be set on an "as available" basis or when the QF has established a LEO; and (4) a minimum contract term of five years.[44] The approved QF rates were not appealed. KYSEIA, while not fully agreeing with the Commission's decision regarding QF rates, does agree that the Commission has the discretion and authority to issue the Kentucky Power QF rates, and that those QF rates comply with federal and state laws and regulations.

The Commission also has the discretion to approve QF rates as proposed by KYSEIA. As indicated in his March 5, 2021, pre-filed testimony, Mr. Barnes, KYSEIA's expert witness, recommended:

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[42] *Federal Parameters on the Definition of Avoided Cost Under PURPA and Legal Methods Currently Used and Acceptable Under PURPA Application for States to Encourage or Discourage Distributed Generation*, UNC Center for Climate, Energy, Environment, and Economics, University of Houston Environment, Energy, and Natural Resources Center, 17-23 (July 1, 2017).
[43] Case No. 2020-00174, (deemed filed Jul. 15, 2020).
[44] Case No. 2020-00174, (Ky P.S.C. Jan. 13, 2021), Order at 60.

- The Company's avoided energy costs under Rider SQF and Rider LQF should be modified to include hedging value and avoided line losses;

- The contract term for Rider SQF should be extended to a minimum of five years;

- Capacity compensation should be established for Rider SQF under the same methodology Mr. Barnes recommended for Rider LQF;

- The Company's proposed revisions to the methodology for establishing energy rates Rider LQF should be rejected, and that the energy rate should include variable O&M expenses, avoided line losses, and hedging value in addition to fuel costs;

- The Commission should direct the Company to modify Schedule LQF to provide that the current capacity calculation methodology only applies during periods of resource sufficiency as indicated by the Company's most recent integrated resource plan ("IRP") or related proceedings in which the Company proposes to build or otherwise acquire capacity;

- The Company's avoided capacity cost during periods of resource insufficiency should be established based on the costs of a proxy unit defined by the Company's most recent IRP as the next unit addition; and

- The Commission should consider establishing a longer term than five years for QF contracts that involve the sale of capacity because capacity planning and acquisition is fundamentally a long-term exercise and the associated avoided capacity costs are long-term in character.[45]

In Mr. Barnes's July 13, 2021, Supplemental Testimony, he briefly summarizes his March 5, 2021, testimony, stating his "opinion remains that the Companies' proposed SQF and LQF tariffs are not fair, just and reasonable," and that, "[m]ost critically, the Companies SQF and LQF tariffs fail to account for their true long-term costs of capacity and the added line loss costs that transmission connected centralized generation incurs due to the physical reality of the electricity delivery system."[46]

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[45] KYSEIA Barnes pre-filed Direct Testimony (filed Mar. 5, 2021) (hereinafter "Barnes Direct"), at 7-8, 14, 23-24 [PDF 9-10, 16, 25-26 of 83].

[46] KYSEIA Barnes Supplemental Testimony (filed Jul. 13, 2021) (hereinafter "Barnes Supplemental"), at 16 [PDF 16 of 18].

In Mr. Barnes's August 5, 2021, Supplemental Rebuttal Testimony, and in response to the Companies revised QF tariffs, he agrees in part, but largely rejects the Companies' QF tariff proposals and expands on his previous testimony by developing a specific rate design that incorporates well-accepted methodologies and utilizes the Companies' own studies and data. Mr. Barnes recommends that the Commission should:

- Accept the Companies' proposal to offer a 20-year fixed rate option under both QF riders;
- Deny the Companies' proposed capacity pricing design and instead adopt the summer on-peak capacity rate design he recommends using the Proxy Method and the Companies' own Loss of Load Probability (LOLP) study and data in its latest Integrated Resource Plan (IRP); and
- Adopt both energy and capacity prices for distribution-connected QFs that reflect the avoidance of energy and demand losses on the transmission system that distribution-connected QFs avoid.[47]

In the alternative, Mr. Barnes recommends that if the Commission declines to adopt his summer on-peak capacity rate proposal and instead elects to rely on a market price-based approach as proposed by the Companies, it should modify the Companies' proposed design as follows:

- Use LevelTen pricing as opposed to the Rhudes Creek PPA as the appropriate market price benchmark;
- Only use LevelTen pricing from only the two most recent quarters to determine the all-in price, resulting in an all-in rate of $35.45/MWh for solar resources;
- Apply the all-in price of $34.45/MWh as a true all-in rate without separate calculation of a capacity rate; and
- Consider the use of an adder or other adjustment to reflect the fact that the LevelTen price indices reflect only the lowest cost offers on the platform rather than average, median, or 50th percentile offers.[48]

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[47] KYSEIA Barnes Supplemental Rebuttal Testimony (filed Aug. 5, 2021) (hereinafter Barnes Supplemental Rebuttal), at 22 [PDF 23 of 66].
[48] *Id.*, at 22-23 [PDF 23, 24 of 66].

Lastly, Mr. Barnes recommends that if the Commission elects to use the Companies' "Peaker" method based on a combustion turbine to determine capacity rates, but does not adopt his summer on-peak rate pricing proposal, the on-peak capacity factor for fixed tilt solar used in the calculation should be modified to reflect his solar LOLP analysis. He also recommends that the peak capacity contribution for single-axis tracking solar be revised using the same methodology.[49]

While Mr. Barnes's written testimony does not directly address the factors promulgated by FERC and the Commission to assist in determining QF rates, his hearing testimony did. KIUC examined Mr. Barnes regarding the various QF rate factors. After KYSEIA Witness Barnes responded to questions concerning the rate factors in 18 CFR 292.304 and 807 KAR 5:054, Section 5, and being questioned about each factor *seriatim*, Mr. Barnes concludes, "I would say it accounts for the majority of those factors, if not all of them."[50]

Again, PURPA and FERC provide factors by which state commissions can consider when determining QF rates, "to the extent practicable," and afford this Commission wide latitude in determining QF rates. While not directly addressed in its written testimony, KYSEIA witness Barnes provided oral testimony confirming that those factors are all addressed in his proposals. KYSEIA's proposals on QF tariffs are fair, just, and reasonable to the electric consumers and in the public interest, and they do not discriminate against qualifying cogenerators or qualifying small power producers. KYSEIA'S proposed avoided cost calculations for Qualifying Facilities' rates comply with Kentucky and Federal Qualifying Facilities' statutes and regulations, and the Commission has discretion to approve such rates.

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[49] *Id*., at 23 [PDF 24 of 66].
[50] VR: 08/18/2021; 18:22:55 *et seq.* (Cross Examination of KYSEIA Witness Barnes).

## II. THE COMPANIES' AVOIDED COST CALCULATIONS FOR QUALIFYING FACILITIES' RATES DO NOT COMPLY WITH KENTUCKY AND FEDERAL QUALIFYING FACILITIES' STATUTES AND REGULATIONS.

In KIUC's cross-examination of KYSEIA witness Barnes, KIUC counsel represents that QFs are entitled to non-discriminatory rates.[51] KYSEIA agrees. To that end, the Companies' avoided costs calculations and proposals for QF rates run afoul of Kentucky and Federal statutes and regulations because those rates are discriminatory against solar QFs. As explained by KYSEIA Witness Barnes, the Companies' QF rates require solar QFs to receive lower credit than other technologies, but, based on data provided by the Companies, solar QFs actually provide a higher benefit, especially at times the Companies' loss of load probability is the highest.[52] The Companies' calculation of capacity rates, which uses different methodologies for different technologies, results in a "discriminatory pricing regime for QFs in which each of the three technology categories (i.e., Solar, Wind, and Other) gets a different capacity rate that is not based on actual avoided costs."[53] Instead, as noted by KYSIEA witness Barnes, "the capacity rate calculation should utilize a single technology neutral methodology based on the cost of a proxy natural gas combined cycle unit based on the next hypothetical addition to the Companies' system in its IRP."[54] The Commission does not have the discretion to approve QF rates that are discriminatory.[55]

## III. KYSEIA'S PROPOSED AVOIDED COST COMPONENT CALCULATIONS FOR THE COMPANIES' NET METERING SUCCESSOR RATES.

### A. Avoided Energy Cost

[51] VR: 08/18/2021; 18:39:12 *et seq.*
[52] Barnes Supplemental Rebuttal (filed Aug. 5, 2021), at 16-20 [PDF 17-21 of 66].
[53] *Id.*, at 6 and 8 [PDF 7, 9 of 66].
[54] *Id.*, at 6 [PDF 7 of 66].
[55] *See* PURPA, Section 210(b), 16 U.S.C. § 824a-3(b).

The minimum amount of the Avoided Energy Cost component, based on the Companies' QF rate proposal with discount factor adjustment adders, is $0.0256/kWh for LG&E and $0.0262/kWh for KU.[56]

The Avoided Energy Cost component of the export rate represents the value of substitute energy form either a purchase or sale standpoint.[57] Consistent with the methodology in the Commission's Order for Kentucky Power Company, the Commission should value avoided energy for the Companies through using the LG&E PJM interface three-year, daytime-only rate (with escalation and discounting over time).[58] The component should incorporate transmission and distribution line losses in calculating avoided cost.[59] The use of the LG&E PJM interface is recommended because it constitutes a readily accessible market for substitute energy and offers transparency in pricing, critical to the methodology.[60]

The Companies propose setting the Avoided Energy Cost component at $0.02319/kWh for NMS-2 customers, which is the same rate developed for qualifying facilities under LQF and SQF for Fixed-tilt Solar based on the average avoided energy cost they calculated for 2022 and 2023.[61] It is, at first blush, unreasonable to set Avoided Energy Cost below the energy rate established for

[56] Barnes, Supplemental Rebuttal (filed Aug. 5, 2021) at 59, Table 8 also at 28 [PDF 29, 60 of 66].
[57] *Id.*, at 26 [PDF 27 of 66].
[58] *Id.* The LMPs, daytime only, averaged from 2017-2019 are reasonable, and, as recognized in Case No. 2020-00174, Year 2020 data should be omitted because of the unprecedented COVID-19 pandemic. Case No. 2020-00174 (Ky P.S.C. May 14, 2021), Order at 27 [PDF 27 of 1,028] (hereinafter the "Kentucky Power Company Order").
[59] *Id.*
[60] KYSEIA acknowledges that an index other than the LG&E PJM interface could be used. Barnes Supplemental Rebuttal (filed Aug. 5, 2021) at 26 [PDF 27 of 66]. However, it is the view of KYSEIA that a single public source is preferred for promoting transparency. *Id.*
[61] *Id.*, at 25 [PDF 26 of 66].

QFs electing the 20-year rate option proposed by the Companies for tariffs SQF and LQF for fixed-tilt solar facilities, $0.02407/kWh.[62]

Net metering customers that install solar facilities are making a long-term investment in a generating facility that has an expected life of at least 25 years.[63] There is no reason to believe that net metering customers will decommission their facilities earlier than the expected life.[64] They have a substantial incentive to keep their systems operating not recoup their significant upfront investment.[65] Indeed, information provided by the Companies reveals that only two out of a total of 1,189 net metering customers (0.11%) have ceased operations.[66]

If the Commission bases avoided energy on the Companies' methodology, two modifications should be made to the methodology.[67] The methodology adopted by the Commission in the Kentucky Power Company Order uses a risk-free discount rate of 1.4%, and this discount rate should be substituted for the 6.57% discount rate used by the Companies in performing the levelized cost operation.[68] Second, a loss adder needs to be applied to the Companies' proposal to reflect avoided transmission and distribution losses. The respective loss adders for LG&E and KU are 5.33% and 7.65% respectively.[69]

### B. Avoided Generation Capacity Costs

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[62] *Id.*
[63] *Id.*
[64] *Id.*
[65] *Id.*, at 30 [PDF 31 of 66].
[66] *Id.*
[67] *Id.*, at 28 [PDF 29 of 66].
[68] *Id.*
[69] *Id.*

The calculated rates for the Avoided Generation Capacity Cost component, based on PJM Net CONE for natural gas combustion turbine and modeled fixed-tilt solar resource are \$0.0391/kWh for LG&E and \$0.0401/kWh for KU.[70]

Excess generation benefits the Companies' customers by allowing them to avoid duplicative capacity investments or purchases.[71] Net metering customers are providing the Companies with a quantifiable capacity value that should be compensated through the Avoided Generation Capacity Cost component of the export rate.[72]

The Commission should use the next hypothetical addition to the Companies' system in developing avoided generation capacity cost.[73] The calculation should utilize a single technology neutral methodology.[74] Using the Companies' most recent Integrated Resource Plan, and based up KYSEIA's understanding of that plan, a natural gas combustion turbine ("CT") is the appropriate proxy capacity unit representing the least-cost source of replacement capacity in the longer-term, even in the high gas price and high CO2 price scenarios.[75] Net CONE meets the objective of public data and data sources and provides "a market based capacity value" specific to the location.[76] Therefore, the PJM Zone 3, UCAP Net CONE for a natural gas CT (three-year average) is

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[70] *Id.*, at 32 [PDF 33 of 66]; *see also* VR: 08/18/2021; 18:17:05 *et seq.*, 18:17:45 *et seq.*, 18:24:05 to 18:24:44, 18:25:25 to 18:19:17, and 18:38:20 to 18:41:30 (Barnes' discussion of his recommendation for a technology neutral approach and his next incremental unit analysis).
[71] *Id.*, at 30 [PDF 31 of 66].
[72] *Id.*, at 29 [PDF 30 of 66].
[73] *Id.*, at 31 [PDF 32 of 66].
[74] *Id.*, *see also* VR: 08/18/2021; 18:25:25 to 18:29:27, *also* Footnote 69, *supra.*
[75] *Id.*, at 31 and 32 [PDF 32 and 33 of 66]; *see also* Case No. 2018-00348, *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (filed Oct. 19, 2018) Vol. 1, page 5-39 [PDF 44 of 117]; VR: 08/18/2021; 18:25:25 to 18:29:17, *also* Footnote 69, *supra*.
[76] Kentucky Power Company Order (Ky P.S.C. May 14, 2021) at 29.

reasonable for use.[77] Additionally, the KYSEIA calculation uses Company-specific demand losses.[78]

Furthermore, system peaks drive the need for capacity investment.[79] System peaks are not evenly distributed across all months and monthly peaks of the year. The assumed solar contribution to peak should be calculated using the weighted LOLP methodology so that it reflects capacity benefits a typical solar net metering facility is forecasted to provide ***relative to the risk of a capacity shortfall at a given hour in the year*.**[80]

The Companies argue that net metering customers should receive no credit for avoided generation capacity costs.[81] They argue, in the alternative, that net metering customers should not receive a credit for avoided generation capacity costs that "exceed the cost that the Companies would incur from purchasing power from a solar purchase power agreement."[82] The Companies calculate the upper bound value at $0.00170/kWh in 2022 and $0.00191/kWh in 2023 based on the Rhudes Creek PPA.[83] Their approach is not reasonable and should be rejected.

The foundation of the Companies' alternative is the use of three methods for calculating avoided cost for different technologies: (1) The Rhudes Creek PPA as a baseline all-in compensation rate; (2) an index of solar and wind PPA prices as the all-in price baseline; and (3)

[77] Barnes Supplemental Rebuttal (filed Aug. 5, 2021) at 32 and 34 [PDF 33, 35 of 66]. KYSEIA states that rates developed based on the PJM Net CONE for NGCC remain reasonable for use within the NMS-2 rate calculation, and the resulting rates, as compared to a natural gas CT, would be nearly identical if a forward-looking two or three year average is used. *Id.*, at 34.
[78] *Id.*, at 32 [PDF 33 of 66].
[79] *Id.*
[80] *Id.*
[81] *Id.*, at 28 [PDF 29 of 66].
[82] *Id.*
[83] *Id.*, at 28 and 29 [PDF 29, 30 of 66].

a bottom-up calculation of capacity cost for a combustion turbine under the "peaker" methodology.[84] From these, they selected the lowest value, the Rhudes Creek PPA.[85]

The Companies refuse to acknowledge the avoided capacity cost benefits of excess generation provided by net metering facilities in contradiction to the Commission's findings in the Kentucky Power Company Order.[86] Furthermore, the Companies refuse to acknowledge how the capacity benefits of variable renewable energy generation is evaluated and compensated in nearly every wholesale market in the United States.[87]

The Companies contend that it is impossible for non-contracted resources to contribute to avoiding new generation capacity investments. The argument is logically and factually incorrect. Excess generation aggregated across net metering customers can be measured, forecasted, planned for, and used to the benefit the Companies' customers to avoid duplicative capacity investments or purchases.[88] The Companies' claim of net metering system attrition is contrary to the evidence. Net metering customers have a direct, substantial incentive to keep their system operating to recoup their significant upfront investment."[89] The fact that only two out of a total of 1,189 net metering customers (0.011 percent) have ceased operating bears this fact out.[90]

The Companies' IRP forecast the deployment of distributed generation, electric vehicle deployment, and demand-side management measures when determining their peak demand and

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[84] *Id.*, at 29 [PDF 30 of 66].
[85] *Id.*
[86] Kentucky Power Company Order (Ky P.S.C. May 14, 2021) at 31.
[87] Barnes Supplemental Rebuttal (filed Aug. 5, 2021) at 29 [PDF 30 of 66].
[88] *Id.*, at 30 [PDF 31 of 66].
[89] *Id.*
[90] *Id*.

energy needs.[91] They ascribe capacity value to DSM measure, even when DSM customers have no contract and no specific obligation.[92] Net metering, likewise, provides capacity value.

The selection of the Rhudes Creek PPA, a single data point, for determining the value of avoided capacity cost is unreasonable. A single PPA price point is not a reliable or transparent cost basis for determining the Avoided Capacity Cost, and it is not reflective of the Companies' long-term avoided capacity costs.[93]

The Companies' "peaker" unit methodology uses a combustion turbine as the proxy unit.[94] To this end, by modeling an NGCT under the "peaker" methodology for one portion of the calculation of their avoided capacity costs, the Companies concede this method to be an appropriate, reasonable methodology for determining avoided capacity rates. Table 4 of Mr. Barnes' Supplemental Rebuttal testimony supplies capacity rates for NMS-II that would result from employing this method, adjusted for line losses and using an annual capacity factor and peak contribution based on Mr. Barnes' modeling.[95] The calculated avoided capacity amounts are largely the same regardless of whether one uses the PJM Net Cone NGCC costs, the PJM Net Cone NGCT costs, or the Company's methodology. KYSEIA asserts that either of these methods are valid given the disagreement over the selection of the proper proxy unit.

With regard to the use of NGCC versus NGCT, KYSEIA makes clear that Mr. Barnes' revisions to his initial recommendation results from new information learned over the course of the proceedings. The Companies disagreement with using an NGCC (despite what their IRP

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91 *Id.*
92 *Id.*
93 *Id.*
94 *Id.*, at 32 [PDF 33 of 66].
95 *Id.*

indicates as the base scenario) has been resolved by demonstrating the proper valuation through relying upon the Companies' own modeling, adjusted for the necessary modifications.

The difference in amounts between the NGCC and the NGCT as the proxy capacity resource stem from three primary facts. First, the Companies use an effective solar capacity contribution of 28.8% for fixed-tilt solar whereas Mr. Barnes' LOLP-based solar capacity contribution produces a 58.14 percent on-peak capacity factor.[96] The amount that Mr. Barnes derived does not reflect the timing of the next capacity need using a discounted levelization process.[97] The Companies did not apply loss factors in their calculations.[98] Nevertheless, the results would be nearly identical if a forward-looking two or three average is used, and either methodology is superior to the Companies' Rhudes Creek single price methodology.[99] The Companies' methodology of choice sets an arbitrarily low upper bound for avoided capacity cost and is unreasonable because it does not reflect the Companies' long-term avoided capacity costs.

### C. Avoided Transmission Capacity Costs

The calculated rates for the Avoided Transmission Capacity Cost component using the LOLP Methodology is $0.01050/$kWh for LG&E $0.02065/$kWh for KU.[100] These rates are also referred to, in this section, as "Year Zero" rates.

The most reasonable approach to calculating avoided transmission cost is to, first, calculate the marginal cost per kW of incremental transmission capacity, second, determine how the solar

[96] *Id.*, at 32 and 33 [PDF 33, 34 of 66].
[97] *Id.*, at 33 [PDF 34 of 66].
[98] *Id.*
[99] *Id.*, at 33 and 34 [PDF 34, 35 of 66].
[100] *Id.*, at 39, 40, and 59 [PDF 40, 41, and 60 of 66].

production shape aligns with the peaks that define cost causation for transmission investment, and, thereafter, calculate the portion of the unit cost of a given kW of PV nameplate can avoid.[101]

While KYSEIA agrees in principle with the methodology used in the Kentucky Power Company Order, in the instant cases devising an escalation rate is problematic. By reference to the cost of service information submitted by the Companies in these rate cases and in each of their prior two rate cases, the annualized escalation of net cost transmission rate base over the four years that have elapsed since the end of the test year in the Companies' 2016 rate cases (June 30, 2018) and the end of the test year for the current rate cases (June 30, 2022) is 9.43% for LG&E and 16.08% for KU.[102] These escalators are based on demonstrated, real increases in transmission investment and costs and, as such, provide a solid measure of cost escalation over recent years.[103] However, assuming that cost escalation in these amounts could produce rather extraordinary levelized long-term avoided cost estimates, it calls the estimates into question.[104]

An alternative approach is to use the escalation in the net cost of service for the same time period, 2.01% for LG&E and 4.19% for KU.[105] The levelized long-term avoided transmission costs using these escalation rates and the 1.4% risk-free discount rate used for the Kentucky Power Company Order results in an Avoided Transmission Rate under the LOLP Methodology of $0.01327/$kWh for LG&E and $0.03426/$kWh for KU.[106] The foregoing alternative analysis is offered for comparison. In view of the uncertainties involved and the potential impact of the

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[101] *Id.*, at 38 [PDF 39 of 66]. Mr. Barnes updated his Supplemental Testimony to correct for the inadvertent use of gross cost of service to calculate unit costs for LG&E, rather than net cost of service. The calculation for KU is not affected by this revision. *Id.*, at footnote 33.
[102] *Id.*, at 40 [PDF 41 of 66].
[103] *Id.*, at 40 and 41 [PDF 42, 43 of 66].
[104] *Id.*, at 41 [PDF 42 of 66].
[105] *Id.*
[106] *Id.; see* Table 6 for Levelized NMS-2 Avoided Transmission Rates for each utility under both the LOLP Methodology and the 6CP Methodology.

escalation rate selection on the rate calculation, the KYSEIA recommendation is that the Year Zero rates calculated above be used in these proceedings.[107]

A starting place to discuss the problems with the Companies' approach is that the Companies do not offer the type of analysis necessary for a robust estimation methodology.[108] The Companies should not be allowed to benefit from ignoring something that they do not study and that other parties cannot perform independently.[109] It also merits mention that the Commission, when estimating Avoided Transmission Capacity Costs, used historical data in the Kentucky Power Company Order.[110]

The calculations provided by the Companies do not actually yield the marginal value of avoided distribution costs for similar reasons described for Avoided Transmission Costs. The Companies' calculation fails to establish a relationship between how costs vary on a capacity unitized basis, which is necessary for computing distributed cost avoidance.[111]

The Companies also use an improperly shortened period of 10 years for calculating both transmission and distribution avoided costs because the failure to examine years 11 through 25 could understate the benefit of distributed generation facilities, particularly if the cost in the later years is higher than the average avoided costs in the first ten years.[112] The Companies' approach is inconsistent with the forward-looking, long-term, and incremental analysis approach adopted by the Commission in its Kentucky Power Company Order. It is unreasonable for the Companies to not consider years 11 through 25.

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[107] *Id.* Refinement of methods used to estimate cost escalation could be pursued in future proceedings.
[108] Barnes Supplemental Rebuttal (filed Aug. 5, 2021) at 38 [PDF 39 of 66].
[109] *Id.*
[110] *Id.*, at 39 [PDF 40 of 66]; Kentucky Power Company Order (Ky P.S.C. May 14, 2021) at 32.
[111] *Id.*, at 43 [PDF 44 of 66].
[112] *Id.*

Each incremental unit of capacity or reduced load has a definable value based upon the unitized avoided marginal costs.[113] Failure to compensate distributed generation customers for small incremental load reductions will undervalue the benefits of excess generation and, as importantly, fail to provide an accurate price signal to DG customers with respect to the value of excess generation. Certainly, the cumulative effect of incremental and small increases in load must be considered because the incremental increases result in incremental transmission costs.[114] Likewise, the same is true for small incremental load reductions provided by distributed generation facilities. The reductions increase available transmission capacity, providing value, including most likely during peak periods when the need to transmit electricity is at its highest.[115] Further, the Companies also fail to reflect the value that is created through increases in available transmission capacity through incremental transmission revenue.[116] The Companies fail to show the relationship between how costs vary on a capacity unitized basis, a relationship necessary for computing the transmission cost avoidance.[117]

Companies argue that net metering customers should receive no compensation for avoided transmission costs, or alternatively $0.00025/kWh for KU and $0.00010/kWh for LG&E.[118] The flaws in the Companies' position are readily apparent. Under the Companies' argument, the price signals that are necessary to facilitate the conditions alleged by the Companies will never be in place.[119] The Companies seek to condition eligibility to receive compensation for this component

[113] *Id.*, at 36 [PDF 37 of 66].
[114] *Id.*
[115] *Id.*, at 37 and 38 [PDF 38, 39 of 66].
[116] *Id.*, at 37 [PDF 38 of 66].
[117] *Id.*
[118] *Id.*, at 35 [PDF 36 of 66].
[119] *Id.*

upon an event that the Companies' price signal is designed to prevent.[120] The Companies' argument needs to be ignored.

The need for transmission is driven by peak needs.[121] The appropriate approach is to examine the peak hours that actually cause transmission costs to be incurred.[122] The focus is upon how distributed generation contributes to peak reductions. Also, there is a need for a gross up of solar contributions to avoided transmission capacity and demand losses.[123] A kW of solar at the point of load avoids transmission capacity at a premium based on losses; clearly, available existing transmission capacity can generate value and that value can be enhanced by transmission load reductions provide by net metering generators.[124]

### D. Avoided Distribution Capacity Costs

The minimum amount of the Avoided Distribution Capacity Cost component is $0.00251/kWh for LG&E and $0.00147/kWh for KU.[125] These rates are also referred to in this section as Year Zero values.

Each incremental unit of capacity or reduced load has a definable value based on the unitized avoided marginal costs.[126] Each incremental kW of load reduction provided by distributed generation offsets an equivalent kW of load increase on the system that contributes to the incurrence of additional distribution investments.[127]

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[120] *Id.*
[121] *Id.*, at 37 [PDF 38 of 66].
[122] *Id.*
[123] *Id.*, at 37 and 38 [PDF 38, 39 of 66].
[124] *Id.*, at 38 [PDF 39 of 66].
[125] *Id.*, at 49 and 59 [PDF 50 and 60 of 66].
[126] *Id.*, at 43 [PDF 44 of 66].
[127] *Id.*

The Commission should use a unit-cost based approach that relies upon: (1) Defining the incremental cost of a given unit of distribution capacity ($/kWh); (2) identifying the alignment of typical solar production to distribution peaks, in the form of an effective solar capacity contribution during typical peak hours percentage; and (3) calculating a rate based on estimated annual energy production from that same hypothetical solar unit.[128] This is functionally the same approach as the unit cost method Mr. Barnes used to calculate avoided transmission costs, and, as with transmission, this rate should be grossed up based on a distribution demand loss factor.[129]

KYSEIA's approach uses the top 10% of residential class load hours to define a solar capacity contribution and a unit cost-based methodology (with gross up for demand losses) that can be derived by dividing net demand-related cost of service by the associated class demand allocator for each Company to produce a $/kW amount.[130] The unit cost amount is then multiplied by the effective solar capacity percentage, which de-rates the unit cost according to the solar contribution to peak.[131] This solar unit value is then divided by modeled annual system production per kW to produce a $/kW rate, and the rate is grossed up for demand losses assuming that facilities are connected at secondary voltage, which are assumed at 5%.[132] The effective solar capacity factor is 14.43% for LG&E and 9.09% for KU.[133] After apply this factor to distribution demand-related unit costs, dividing by annual solar production and adding a demand loss adder produces a Year Zero distribution avoided cost $0.00251/kWh for LG&E and $0.00147/kWh for KU.[134]

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[128] *Id.*, at 45 [PDF 46 of 66].
[129] *Id.*
[130] *Id.*; and Barnes Supplemental (filed Jul. 13, 2021) at 10 and 11 [PDF 10, 11 of 18].
[131] Barnes Supplemental (filed Jul. 13, 2021) at 10 [PDF 10 of 18].
[132] *Id.*
[133] Barnes Supplemental Rebuttal (filed Aug. 5, 2021) at 45 [PDF 46 of 66].
[134] *Id.*

Failing to compensate distributed generation customers for small incremental load reductions undervalues the benefit of excess generation.[135] The need for distribution is driven by peak needs.[136] Demands on the distribution system are driven by maximum class demands. If unitized kWh costs are used, they must be adjusted to reflect the contribution that solar provides during those peak hours that cause distribution costs to be incurred. The Companies' proposal fails through dividing costs across all kWh of consumption to produce a rate that fails to account for how distributed generation exports contribute to peak reductions.[137]

By providing generation at the point of load and excess generation to nearby neighbors, distributed generation facilities reduce load on the distribution system substations during peak periods, which allows load increases that might otherwise trigger a need for upgrades to existing distribution system facilities.[138] These real, incremental distribution system benefits should be compensated accordingly.[139]

While maximum class demand during a single hour is frequently used as a measure of cost causation for the distribution system, it is relatively imprecise because individual distribution circuits peak at different times depending on the character of the loads they serve.[140] Few, if any, distribution circuits exclusively serve residential customers and by and large non-residential classes tend to peak later in the morning or earlier in the evening in than the residential class.[141] Although it may not be possible to more precisely define cost responsibility on a circuit-by-circuit basis, using an average of high class loads hours helps introduce diversity reflective of the diversity

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[135] *Id.*, at 43 [PDF 44 of 66].
[136] *Id.*, at 44 [PDF 45 of 66].
[137] *Id.*
[138] *Id.*
[139] *Id.*
[140] *Id.*, at 47 [PDF 48 of 66].
[141] *Id.*

of load on the distribution system.[142] Using an average of solar production during high load hours rather than a single hour mitigates the potential for large swings in solar value attribution that may be transitory artifacts of a specific test year.[143] It is not proper to rely upon a single peak hour for cost allocation or in any context.

As an alternative approach to the embedded unit cost approach for estimating the marginal cost of distribution capacity, Mr. Barnes used incremental load carrying capability of planned distribution investments in the Companies' portfolio in combination with the annualized carrying costs Mr. Seelye used in his calculations to calculate implied marginal distribution capacity costs in unitized ($/kW) figures.[144] Applying the same effective solar contribution and loss factors to these unit costs produces similar, though slightly higher, avoided distribution cost rates of $0.00297/kWh for LG&E and $0.00306/kWh for KU.[145]

As between the implied marginal cost approach and the embedded unit cost approach, KYSEIA recommends rates derived based upon the embedded cost approach. First, it is consistent with the method recommended for the transmission cost component. Second, the implied marginal costs are based on the Companies' data that merits further review. Specifically, it is not clear that Companies' business plans serve as a good long-term predictor of future distribution investments. Also, it is not clear that no changes are necessary to the Companies' method for categorizing costs as load-related versus non-load-related. The potential material impact associated with these uncertainties renders the implied marginal cost approach less reliable.

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142 *Id*.
143 *Id.*, at 46 and 47 [PDF 47, 48 of 66].
144 *Id.,* at 47 and 48 [PDF 48, 49 of 66].
145 *Id.*, at 48, Table 7 [PDF 49 of 66].

As with the transmission cost component, there are concerns about recommending a specific escalation rate for distribution costs. The KYSEIA recommendation is to the Year Zero values, which is sufficiently similar to assuming a moderate escalation in costs at the same rate as the risk-free discount rate (1.4%).[146] The KYSEIA distribution escalation rates based on net cost rate base are 8.8% for KU and 8.6% for LG&E.[147] The alternative amounts based upon residential net cost of service are negative (0.86%) for LG&E and 0.43% for KU.[148] As with transmission cost, there are reservations, refinements in further proceedings that are necessary.

The Companies argue that net metering customers should receive no compensation for avoided distribution costs.[149] In the alternative, they argue that Avoided Distribution Costs are, "at most," $0.00046/kWh for KU and $0.00012/kWh for LG&E.[150] The Companies' proposal for the avoided distribution cost component is unreasonable.

As with their position on Avoided Transmission Costs, the flaws in the Companies' position are readily apparent. Once again, under the Companies' argument, the price signals that are necessary to facilitate the conditions alleged by the Companies will never be in place.[151] The Companies seek to condition eligibility to receive compensation for this component upon an event that the Companies' price signal is designed to prevent.[152] The Companies' argument needs to be ignored.

### E. Avoided Ancillary Services Cost

146 *Id.*
147 *Id.*
148 *Id.*, 48 and 49 [PDF 49, 50 of 66].
149 *Id.*, at 42 [PDF 43 of 66].
150 *Id.*
151 *Id.*
152 *Id.*, at 35 [PDF 36 of 66].

Avoided ancillary services cost are a stack in the net metering export rate. The component should be forward-looking.[153] The PJM pricing used for the Kentucky Power Company is a reasonable proxy for the Companies' avoided ancillary services cost as it represents a market-based measure for the costs of these services.[154] For both KU and LG&E, the Avoided Ancillary Services Cost is $0.0006/kWh.[155]

**F. Avoided Carbon Cost**

PPL Corporation, the parent company of KU and LG&E, concedes the following regarding how climate change could negatively impact its costs and its operations:

> PPL's business could be subject to a variety of risks associated with the potential effects of climate change. Among those risks, climate change may produce stronger and more frequent severe weather, disrupting operations and increasing the costs to prepare for, and respond to, weather events.[156]

In addition to the risk climate change poses to the Companies' ability to serve its customers, the Companies face a real risk that new state or federal policies could impose a price on carbon emissions.[157] Nevertheless, while PPL's Climate Assessment "analysis does not explicitly use carbon price as an input to the modeling," it notes that "the implied cost of CO2 emissions may be greater than zero in the [Clean Power Plan] scenario" considered in its analysis.[158] The Companies, likewise, used a very low projected future CO2 cost based upon a low carbon price scenario form

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[153] Barnes Supplemental (filed Jul. 13, 2021) at 7 [PDF 7 of 18]; Kentucky Power Company Order (Ky P.S.C. May 14, 2021) at 32.
[154] *Id.*
[155] Barnes Supplemental Rebuttal (filed Aug. 5, 2021) at 59, Table 8 [PDF 60 0f 66].
[156] PPL Corporation, "PPL Corporation Climate Assessment Assessing the Long-term Impact of Climate Policies on PPL," November 2017, Page 1, available at https://www.pplweb.com/wp-content/uploads/2017/12/Climate-Assessment-Report.pdf.
[157] Barnes Supplemental Rebuttal (filed Aug. 5, 2021) at 51 [PDF 52 of 66].
[158] *Id.*, *citing* PPL Corporate Climate assessment at 2.

a 2016 analysis in its most recent IRP.[159] Finally, PPL itself has, since the filing of testimony for the additional proceedings, proactively set "an ambitious goal to achieve net-zero carbon emissions by 2050" with at least an 80% from 2010 levels by 2040.[160] The Companies' claim that the carbon-free nature of excess generation provided by net metering facilities provides no value now and for decades to come lacks credibility.[161]

Distributed generation will provide tangible avoided carbon cost benefits for at least 25 years into the future.[162] Consistent with the Commission's Order for Kentucky Power Company, the Avoided Carbon Cost component of the export rate should be developed through a forward-looking, long-term, and incremental analysis.[163] Excess generation provided by net metering has value, and the Avoided Carbon Costs include both from any carbon pricing and reduction in operating costs reduced carbon emissions.[164]

The Commission should use a single value for both Companies.[165] The Companies' 2018 IRP contains a forecast of the base system energy mix and fuel burn by fuel type in Table 8-17. This information can be used to develop a forecasted emissions profile, though it does not appear to incorporate an updated assumption on potential coal plant retirements or, more generally, the PPL objectives of achieving a 70 percent reduction in carbon emissions from 2010 levels by 2035 and net zero emissions by 2050.[166]

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159 *Id.*

160 *Id.*, at 52 for original testimony [PDF 53 of 66]. *See* [www.pplweb.com/sustainability/climate-action/](www.pplweb.com/sustainability/climate-action/) for PPL's increasingly stringent goal for reducing carbon emissions.

161 *Id.*

162 *Id.*, at 50 [PDF 51 of 66].

163 *Id.*; *see also* Kentucky Power Company Order (Ky P.S.C. May 14, 2021), at 23 and 35.

164 *Id.*, at 52 [PDF 53 of 66].

165 *Id.*

166 *Id.*, at 53 [PDF 54 of 66], *see* Footnote 160, *supra* for PPL's increasingly stringent goals for reducing carbon emissions.

The Commission should use, as an approximation, the same rate adopted for Kentucky Power Company, \$0.00578/kWh.[167] The Companies' current energy mix is not dramatically different than Kentucky Power Company's, and the Companies actually use somewhat higher carbon prices in the sensitivity analysis they conducted as part of their 2018 IRP.[168] Specifically, the Companies state a carbon price of \$17.00/ton in 2026 escalating to \$26.00 in 2033.[169] Comparatively, Kentucky Power Company assumed a zero carbon price through 2028 and a carbon price of only \$17.82/ton in 2033.[170] Furthermore, the Companies' base energy forecast form the 2018 IRP retains coal and gas generation at roughly their present levels rather than reducing them over time.[171] If anything, use of the Kentucky Power Company's Avoided Carbon Cost rate understates the Companies' future carbon costs.

Alternatively, it could be reasonable to attempt to construct an estimate by trending emissions downward to meet a 2040 emissions reduction target and using projected coal retirement dates as inflection points in the trending process.[172] Such an approach would still require assumptions to be made about replacement resources, for example, gas versus zero-carbon resources.[173]

### G. Avoided Environmental Compliance Cost

The Commission should apply a levelized \$/kWh amount based upon a forward projection of all the environmental compliance costs for the Companies.[174] The lack of necessary data to

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[167] *Id.*; *see also* Kentucky Power Company Order (Ky P.S.C. May 14, 2021), at 36.
[168] *Id.*
[169] *Id.*, at 53, 54, and Footnote 50 at 54 [PDF 54, 55 of 66]
[170] *Id.*, at 54 [PDF 55 of 66].
[171] *Id.*
[172] *Id.*, at 53 [PDF 54 of 66].
[173] *Id.*
[174] *Id.*, at 57 [PDF 58 of 66].

perform the calculation to develop a recommendation does not eliminate the existence of this avoided cost.[175]

All relevant environmental compliance costs on a long-term, forward-looking basis should be included in the Avoided Environmental Costs, not just short-run variable costs, including forecasted capital investments at a unit to address or mitigate environmental issues in compliance with applicable regulations.[176]

Exports from one distributed generation facility may not remove the need for specific transmission or distribution capacity investment. Nonetheless, distributed generation facilities can, in the aggregate, reduce the need for fossil plants and their associated investments related to environmental control technologies over the long-run. Net metering customers should be compensated for this benefit of reducing risk to the Companies and their customers of future environmental compliance costs that could be imposed through future state or federal regulations or legislation.[177]

The Companies argue that there should be no compensation for Avoided Environmental Costs because "avoided environmental costs are fully accounted for in the avoided energy and capacity costs components."[178] Further, the Companies argue that Avoided Capacity Costs calculation reflects environmental costs associated with regulations that result in the retirement of generating units.[179]

The first problem is that they have not transparently identified what their environmental compliance costs are as requested by the Commission. Second, the Companies do not actually

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[175] *Id.*
[176] *Id.*, at 56 [PDF 57 of 66].
[177] *Id.*
[178] *Id.*, at 54 and Footnote 51 at 54 [PDF 55 of 66].
[179] *Id.*, at 55 [PDF 56 of 66].

reflect a completed and long-run view of environmental costs that could impact retirement of its generating units.[180] The likely impacts of additional environmental regulations on fossil generating facilities should not be ignored. They should be considered when evaluating the Avoided Environmental Costs of net metering facilities operating 25 years or more into the future.[181]

As noted above, all relevant environmental compliance costs should be considered. Coal combustion residual ("CCR") costs are an example of where the Companies have adjusted their Avoided Energy Cost to account for "opportunity cost for lost CCR revenues," but the Companies do not appear to account for the potentially substantial costs of CCR environmental compliance.[182] In terms of symmetry of benefits offsetting costs and consistency, if the prospect of such lost revenues is incorporated into the avoided energy rate, then the Cost of CCR mitigation must likewise be reflected as an environmental cost.[183]

### H. Jobs and Economic Benefits Component

The Commission should direct the Companies to evaluate job benefits and economic development as an export rate component for their next rate case filings through an unbiased and objective valuation. The evaluation should be a transparent, forward-looking evaluation that calculates benefits on a per kWh basis for behind the meter resources.

In the instant cases, it should be considered as a qualitative factor because the Companies have not quantified this component. The Commission should default to the higher-end of the quantitative estimates of the other cost categories of benefits, and the Commission should maintain monthly netting under tariff NMS-2 in order to counter-act the Companies' undervaluing of excess

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[180] *Id.*
[181] *Id.*, at 56 [PDF 57 of 66].
[182] *Id.*
[183] *Id.*

generation of a net metering customers while staying within the range of reason for establishing fair, just and reasonable rates.[184]

Distributed generation is providing, among other things, economic benefits to the Commonwealth of Kentucky including job creation and capital investment.[185] As noted by KYSEIA previously in these proceedings, among the resources available for considering the economic benefits of solar resources, including behind the meter resources, is a 2018 report prepared for the Maryland Public Service Commission.[186] As part of the report, "the economic and job impacts of incremental investment in distributed solar resources in the territories of the four Maryland IOUs" were calculated.[187] The study demonstrates that the direct job and economic impacts of behind the meter solar projects are (1) substantial and (2) quantifiable.[188]

Economic development has been part and parcel of ratemaking for decades.[189] It is well-withing the Commission's jurisdiction to order the Companies to study jobs and economic benefits as a component of a net metering export rate.

## IV. The Commission Should Use a Monthly Netting Period.

"Net metering" is based upon a difference of electricity supplied by a customer to the grid and by the utility to the customer over a billing period, rather than a portion of a billing period or consideration of instantaneous imports and exports which would limit the amount of self-consumption that a customer-generator could otherwise achieve.[190] KYSEIA continues to assert

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[184] *Id.*, at 58 and 59 [PDF 59, 60 of 66].
[185] Kentucky Power Company Order (Ky P.S.C. May 14, 2021) at 38, footnote 122.
[186] *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland* (dated November 2, 2018), Daymark Energy Advisors. The report is attached as an exhibit to this memorandum.
[187] *Id.*, at Section 5.4, page 188 [PDF 206 of 245].
[188] *Id.*, at Section 5.4.1, pages 195 through 197 [PDF 213 – 215 of 245].
[189] Kentucky Power Company Order (Ky P.S.C. May 14, 2021), at 37 and 38.
[190] *See* KRS 278.465(4).

that the reasonable interpretation of the billing period requirement is that exports within a billing period, measured in kWh, should continue to be netted against imports within a billing period, measured in kWh.

Thus, the export rate concerns the compensation for net excess generation, if any, that occurs by reference to the entire billing period. The Companies' proposed bill calculation method is at odds with the intent for a billing period determination. Additionally, the Companies' bill calculation proposal significantly increases the complexity of the NMS-2 rate design in the absence of any clear demonstration of benefit. Typical residential and small customers are unable to realistically plan for, monitor, or respond to second-by-second changes in their generation and consumption so as to limit the quantity of exports, which would be necessary for them under NMS-2 to maximize the economic benefits of their net metering facilities to avoid being undercompensated for instantaneous exports. The Companies' "solution" for net metering customers – the installation of battery storage to limit exports – would entail a massive additional expense to net metering customers that is both extremely onerous to customers and completely unjustified by the Companies. The Companies' proposed bill calculation should be rejected.[191]

## V. Joint Account Ownership Issues.

The Companies, the Joint Intervenors, the Kentucky Office of the Attorney General, Commission Staff, and KYSEIA worked together, with notice and opportunity provided to the other parties of record, to prepare recommendations for tariff issues concerning joint account ownership. KYSEIA participated in the drafting of the recommendations, agreed to submit the language to the Commission, and requests its approval.

[191] *See* Kentucky Power Company Order (Ky P.S.C. May 14, 2021) at 24 and 25.

WHEREFORE, for the foregoing reasons, KYSEIA respectfully requests that the Commission deny the Companies' proposed rates for qualifying facilities and net metering service and set rates consistent with the recommendations in this Memorandum Brief. KYSEIA also requests a monthly netting period and recommends the approval of the joint account ownership recommendations submitted to the Commission by the Companies, Joint Intervenors, the Kentucky Office of the Attorney General, and KYSEIA (and upon consultation with Commission Staff)..

Respectfully submitted,

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## Notice And Certification For Filing

Undersigned counsel provides notice that the electronic version of the paper has been submitted to the Commission by uploading it using the Commission's E-Filing System on this 7th day of September 2021, and further certifies that the electronic version of the paper is a true and accurate copy of each paper filed in paper medium. Pursuant to the Commission's March 16, 2020, March 24, 2020, and July 22, 2021 Orders in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus Covid-19*, the paper, in paper medium, is not required to be filed.

/s/ David E. Spenard
David E. Spenard

## Notice Regarding Service

The Commission has not yet excused any party from electronic filing procedures for this case.

/s/ David. E. Spenard
David E. Spenard