COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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**

In the Matter of:

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**

SUPPLEMENTAL REBUTTAL TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: August 5, 2021

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I. INTRODUCTION AND PURPOSE

Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the supplemental testimonies of Kentucky Solar Industries Association ("KSIA") witness Justin R. Barnes and Joint Intervenors witnesses James Owen and Karl R. Rábago regarding claims that: (1) the Companies did not adequately support their Rider NMS-2 compensation rate proposal; (2) NMS-2 compensation rates should include a jobs and economic development component, which the Companies should support with a study; (3) the Commission should include social and societal benefits components in NMS-2 compensation rates; (4) the Commission should require a monthly netting period for NMS-2; and (5) Mr. Barnes's proposals regarding net metering credit transfers and account opening.

II. THE COMPANIES' ORIGINAL RIDER NMS-2 PROPOSAL WAS REASONABLE AND SUPPORTED BY CREDIBLE EVIDENCE

Q. The Joint Intervenors' witnesses have testified that the Companies must perform a comprehensive cost-benefit study to support their proposed Rider NMS-2 compensation rate, asserting that the Companies have "failed to provide credible

and competent evidence or to propose a transparent, fair, just, and reasonable methodology for establishing a compensation rate."[1] Do you agree?

A. No. First, the Companies proposed a Rider NMS-2 compensation rate in these proceedings that they believed was fair, just, and reasonable for all customers, including the vast majority of customers who are not and never will be net metering customers but who will have to pay the compensation rate the Commission establishes for energy they supply to the grid. The Companies' proposed NMS-2 compensation approach was based on established cost of service principles and the touchstone of Kentucky regulation, i.e., least cost resource acquisition. The Companies made their NMS-2 proposal in November 2020 when they filed their applications in these proceedings, more than six months before the Commission issued its order establishing its new net metering compensation rate framework in Kentucky Power Company's recent rate case.[2] Therefore, it is neither reasonable nor rational to criticize the Companies for making a proposal that did not address a framework that did not exist at the time.

Moreover, now that the Commission has established its framework, it is unfounded for the Joint Intervenors' witnesses to suggest the Companies' original NMS-2 proposal was flawed because the Companies did not conduct a Value of Solar analysis of the kind the Joint Intervenors' witnesses appear to prefer.[3] Mr. Rábago testified in the recent Kentucky Power Company rate case and advocated a broader

[1] Rábago Supplemental Testimony at 6.
[2] *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, Order (PSC Ky. May 14, 2021).
[3] *See, e.g.,* Rábago Supplemental Testimony at 3-5; Owen Supplemental Testimony at 2-9.

Value of Solar-type analysis; the Commission chose to establish the framework it did nonetheless.[4] In these proceedings, the Commission received extensive testimony from the Joint Intervenors' witnesses and KSIA's witnesses regarding possible analyses and factors to include in setting NMS-2 compensation, yet the Commission directed the parties to file supplemental testimony on the factors it established in the Kentucky Power proceeding, not about what other factors might be included or the parties wish were included. Thus, there is no merit to any assertion that the Companies must perform an analysis to address factors beyond what the Commission has established.

Finally, I would observe that the Companies' originally proposed NMS-2 compensation rate, i.e., the Companies' current non-time-differentiated SQF rate of \$0.02173/kWh, is entirely consistent with evidence concerning genuinely avoidable costs under the Commission's Kentucky Power factors. As the Companies' witnesses David S. Sinclair and W. Steven Seelye demonstrate in their supplemental and supplemental rebuttal testimonies, five of the Commission's eight cost factors—avoided energy cost, avoided generation capacity cost, avoided ancillary services cost, avoided carbon cost, and avoided environmental compliance cost—are equally well avoided by solar power purchased under long-term power purchase agreements as they are by energy generated by net metering customers.[5] Regarding avoided transmission and distribution costs, the supplemental and supplemental rebuttal testimonies of Beth McFarland and John K. Wolfe show it is unlikely there will be any such avoided costs resulting from net metering in the current planning horizon, even if net metering

[4] *See, e.g.,* Case No. 2020-00174, Rábago Supplemental Testimony (Ky. PSC Feb. 25, 2021).
[5] *See, e.g.,* Seelye Supplemental Testimony at 8-25 and 28-29; Sinclair Supplemental Testimony at 19-21.

capacity reached its current statutory cap.[6] And as I previously testified and reiterate here, it would exceed the Commission's statutory authority to include an explicit jobs benefit in NMS-2 compensation rates.[7] Translating these factors into numbers, the Companies' recent solar power purchase agreement with Rhudes Creek Solar LLC ("Solar PPA") price net of current renewable energy credit ("REC") prices is $0.02082 (PPA price of $0.02782 less $0.00700 REC revenues).[8] Grossing up that value for 4% line losses as proposed by Mr. Seelye results in $0.02169/kWh, which is almost exactly what the Companies proposed for their NMS-2 compensation rate. Therefore, the Companies' original NMS-2 proposal was reasonable at the time the Companies proposed it, and it remains reasonable under the seven Kentucky Power factors that are jurisdictional to the Commission.

That aside, the Companies have presented in their supplemental testimony and further support in their supplemental rebuttal testimony additional evidence regarding a reasonable range of NMS-2 compensation rates based on the Kentucky Power framework.

III. A JOBS BENEFIT AND ECONOMIC DEVELOPMENT STUDY IS NEITHER APPROPRIATE NOR REQUIRED BECAUSE SUCH BENEFITS ARE BEYOND THE COMMISSION'S JURISDICTION

Q. Mr. Barnes asserts, "There is no valid reason for the Companies to ignore the substantial and quantifiable job and economic impacts when determining their net metering export rates."[9] Do you agree?

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[6] *See, e.g.,* McFarland Supplemental Testimony at 5; Wolfe Supplemental Testimony at 6.

[7] Conroy Supplemental Testimony at 4-10.

[8] The Companies' recent solar power purchase agreement with Rhudes Creek Solar LLC provides 20-year level pricing of $0.02782/kWh including RECs. Current Ohio solar REC prices are about $7.00/MWh. *See* https://www.srectrade.com/markets/rps/srec/ohio (accessed July 22, 2021).

[9] Barnes Supplemental Testimony at 12-13.

A. No. Every part of Mr. Barnes's assertion is either incorrect or entirely unsupported.

With regard to his assertion that the Companies lack a "valid reason" not to include job and economic impacts in NMS-2 compensation rates, as I demonstrated at length in my supplemental testimony, job creation benefits per se are beyond the Commission's jurisdiction. Precisely the same arguments and precedents apply to claimed economic development resulting from eligible customer-generators' facility installation and maintenance. Therefore, because adding such an NMS-2 compensation component would be impermissible under existing law, the Companies have a *compelling* reason not to include claimed job and economic impacts in NMS-2 compensation rates.

Moreover, including such a compensation component would be inconsistent with the Commission's orders in the Companies' recent solar power purchase agreement proceeding, Case No. 2020-00016.[10] In that proceeding, the Companies proposed to allow two significant, long-term Kentucky employers that have collectively invested billions of outside dollars in Kentucky to use the output of a solar facility for which they would pay to offset their intermediate and peak demands if the facility's output actually—not theoretically—coincided with their own demands.[11] The Companies did not propose to allow offsets for base demand charges, which cover transmission and distribution costs, and they certainly did not propose to give the customers, Toyota and Dow, subsidies for being employers or creating economic

[10] *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source under Green Tariff Option #3,* Case No. 2020-00016, Order (PSC Ky. Dec. 16, 2020); Case No. 2020-00016, Order (PSC Ky. June 18, 2020); Case No. 2020-00016, Order (PSC Ky. May 8, 2020).

[11] Case No. 2020-00016, Application (Ky. PSC Jan. 23, 2020).

development.[12] The Commission agreed with not giving Toyota and Dow base demand offsets, but went further and denied intermediate and peak demand offsets:

> Toyota and Dow will receive a subsidy because nonfirm energy produced by the solar facility offsets Toyota's and Dow's demand, resulting in a shift in cost recovery of fixed assets in subsequent rate proceedings from Toyota and Dow to LG&E/KU's nonparticipating customers.[13]

Given the Commission's decision not to allow two large employers to offset generation-only demands based on *actual* solar facility production coinciding with their own *actual* demands, it would be inconsistent at best to give NMS-2 customers not only payment in advance, as it were, for merely anticipated demand reductions but also an additional subsidy for claimed jobs and economic benefits purportedly resulting from the rooftop solar industry.

Also, it is not clear why the Commission would want to provide a non-utility-cost-related subsidy to a business sector that is demonstrably uneconomical. As Mr. Sinclair shows in his supplemental rebuttal testimony (and as the evidence the Companies filed previously in the record of these proceedings shows), rooftop solar is significantly less economical than utility-scale solar, and not by a small margin: rooftop solar capacity is much costlier than utility-scale solar capacity and much less efficient, resulting in a cost per kWh that is two to three times that of utility-scale solar.[14] The cost inefficiencies of small-scale, particularly rooftop, solar appear to be inherent and permanent relative to the efficiencies of scale associated with large, utility-scale solar facilities: data from the national Solar Energy Industries Association shows that the

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[12] *Id.*
[13] Case No. 2020-00016, Order at 6-7 (PSC Ky. June 18, 2020).
[14] *See, e.g.,* Companies' Responses to PSC 6-7(c) and 6-32.

"soft costs," i.e., non-hardware costs, of residential solar installations remained essentially unchanging at about $2.00/Watt from 2014 through 2020, whereas data from the Lawrence Berkeley National Laboratory indicates the median fully installed cost—soft costs *and* hardware costs combined—for utility-scale solar projects was less than $2.00/Watt—AC or DC—in 2018 and 2019.[15] Respectfully, the Commission should not compel the Companies' customers to pay extra to help support an inefficient and uneconomical business sector in the name of jobs and economic development.

Finally, the Commission has long held that utilities have an obligation to serve customers at the lowest reasonable cost,[16] which I discussed in my rebuttal testimony in these proceedings.[17] Indeed, more than 30 years ago the Commission characterized this obligation as a statutory imperative: "LG&E has a statutory obligation under KRS 278.030 to serve its customers at the lowest reasonable cost."[18] Nothing in KRS 278.466 amends or rescinds this statutory obligation. Indeed, in the Companies' recent proceeding regarding its Solar PPA, the Commission—quoting the Kentucky Supreme Court—stated, "[O]ne of the Commission's 'most important roles' in administering KRS Chapter 278, 'is to provide the lowest possible cost to the rate payer.'"[19]

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[15] Companies' Response to PSC 6-32.

[16] *See, e.g., An Investigation of Electric Rates of Louisville Gas and Electric Company to Implement a 25 Percent Disallowance of Trimble County Unit No. 1*, Case No. 10320, Order at 19 (Ky. PSC Oct. 2, 1989) ("LG&E has a statutory obligation under KRS 278.030 to serve its customers at the lowest reasonable cost."); *Application of Big Rivers Electric Corp. for a General Adjustment in Its Rates*, Case No. 2009-00040, Order at 2 (Ky. PSC Aug. 14, 2009) ("Big Rivers must be diligent in determining future expenses, as well as capital investments, to ensure that it is providing a high quality of service at the lowest reasonable cost."); *Application of The Union Light, Heat and Power Company for Certain Findings under 15 U.S.C. Sec. 79Z*, Case No. 2001-00058, Order at 7 (Ky. PSC May 11, 2001) ("The Commission believes that reviewing ULH&P's power supply alternatives will be critical to assuring northern Kentucky that it will have a long-term reliable power supply at the lowest reasonable cost.").

[17] Conroy Rebuttal at 12-13.

[18] *An Investigation of Electric Rates of Louisville Gas and Electric Company to Implement a 25 Percent Disallowance of Trimble County Unit No. 1*, Case No. 10320, Order at 19 (Ky. PSC Oct. 2, 1989).

[19] Case No. 2020-00016, Order at 7 (PSC Ky. Dec. 16, 2020), *quoting Public Service Comm'n v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986) ("The Commission has ignored one of its most important roles, which is to provide the lowest possible cost to the rate payer.").

Therefore, the objective in setting an NMS-2 compensation rate that is fair, just, and reasonable for all customers—including the vast majority who will never be net metering customers but who will pay for energy purchased under NMS-2—should be to pay the *lowest reasonable cost* for that energy, not to find ways to artificially or extra-jurisdictionally inflate what all customers must pay. Thus, if the Commission's longstanding lodestar of lowest reasonable cost is to be taken seriously, there cannot be a "jobs and economic development" component of NMS-2 compensation rates.

If the Commission determines to add a jobs and economic benefit component notwithstanding the clear jurisdictional concerns, it must ensure such a component is based on a net and nuanced calculation. For example, it must include the effects on jobs and the Kentucky economy of reduced usage of other energy sources, including coal-related jobs and economic activity. It must also be sufficiently nuanced to remove any contribution to claimed job creation and economic development related to installing, repairing, and maintaining NMS-1 customers' facilities; otherwise customers will be paying twice for the same asserted benefits. And it must account only for job creation and economic development resulting from the Companies' NMS-2 customers, not net metering customers in other service territories. Omitting these and potentially other factors would result in a skewed and inaccurate job creation and economic development component. But there is no amount of netting and nuance that can cure the jurisdictional issue, and the Commission should refuse to include such a compensation component in NMS-2 at all.

IV. THE COMMISSION SHOULD REFUSE TO ADD SOCIETAL BENEFITS COMPONENTS TO NMS-2 COMPENSATION RATES BECAUSE THEY ARE

OUTSIDE THE COMMISSION'S JURISDICTION AND ARE EQUALLY PROVIDED BY UTILITY-SCALE SOLAR

Q. Messrs. Owen and Rábago have testified that claimed social or societal benefits of solar should be included in calculating NMS-2 compensation rates.[20] Do you agree?

A. No. For all the same reasons I just discussed concerning a "jobs and economic development" component of NMS-2 compensation rates, the Commission should refuse to include other claimed social or societal benefits of solar, such as "Health Liability" or the "social cost of carbon," in NMS-2 compensation rates: they are beyond the Commission's jurisdiction and are contrary to lowest-reasonable-cost ratemaking.[21]

In addition, the claimed social and societal benefits of solar generation are equally available from utility-scale solar as from net-metering-scale solar. Nearly all, if not all, of these claimed benefits result from the zero-carbon-emitting nature of solar generation; rooftop solar and utility-scale solar are equally zero-carbon emitting. Thus, consistent with lowest-reasonable-cost principles, there is *no reason to pay a premium* over utility-scale solar prices to purchase energy under NMS-2 to obtain exactly the same benefits, regardless of what those benefits are. As Mr. Sinclair's supplemental rebuttal testimony shows, utility-scale solar can be readily contracted for in the Companies' service territories for a 20-year level price of less than $0.03/kWh. That stands in stark contrast to the underlying economics of rooftop solar, which requires about $0.09/kWh to be economical, yet it provides *exactly the same benefits per kWh* (though the Companies agree it is necessary to adjust for avoided transmission and

[20] *See, e.g.,* Owen Supplemental Testimony at 7-8 (addressing the social cost of carbon); Rábago Supplemental Testimony at 5 (recommending including "Health Liability" in NMS-2 compensation).
[21] *Id.*

distribution capacity costs and line losses, if any). The point is that utility-scale solar prices are the lowest reasonable costs of obtaining solar energy of which the Companies are aware, and they—not a hypothetical and largely subjective "Value of Solar," however constructed—should be the basis for setting NMS-2 compensation rates, in large part because the benefits created by utility-scale solar are *exactly the same* as those created by net-metering-scale solar.

V. THE COMMISSION SHOULD REJECT A BILLING-PERIOD NETTING INTERVAL AS CONTRARY TO STATUTE AND THE REALITY OF HOW NET METERING WORKS

Q. Messrs. Barnes and Rábago have testified the Commission should use a billing-period netting interval for NMS-2.[22] Do you agree?

A. No. There are two reasons the Commission should refuse to impose a billing-period netting interval for NMS-2. First, such a netting interval would be contrary to the plain language in KRS 278.465(4), which clearly states that net metering is defined as the difference between two dollar values, not two kWh amounts. The two dollar values to be netted are (1) the dollar value of "*all* electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period and priced as prescribed in KRS 278.466" and (2) the dollar value of "*all* electricity consumed by the eligible customer-generator over the same billing period and priced using the applicable tariff of the retail electric supplier."[23] There is no ambiguity in the statute as applied to the Companies: every kWh that flows to the Companies' grid is priced at the NMS-2 compensation rate and credited to the customer-generator, and every kWh the customer consumes from the grid is priced at the applicable tariff rate and billed to

[22] Barnes Supplemental Testimony at 14; Rábago Supplemental Testimony at 2.
[23] KRS 278.465(4) (emphasis added).

the customer. That interpretation is the only one consistent with KRS 278.466(3), which states, "A retail electric supplier serving an eligible customer-generator shall compensate that customer for *all* electricity produced by the customer's eligible electric generating facility that flows to the retail electric supplier …."[24] The Companies believe that when a statute says "all," it means "all."

In contradistinction, Messrs. Barnes and Rábago would have the Commission read the statute that says "all" to mean "some," and in most cases "less than half of." They would have the Commission ignore the clear statutory directive to net the dollar value of *all* kWh a customer-generator produces to the grid and the dollar value of *all* energy the customer-generator consumes from the utility. They would have the Commission rewrite the statute to include a kWh netting step before the dollar valuing occurs; indeed, in every billing period for every NMS-2 customer, they would effectively have the Commission ignore exactly half of KRS 278.465(4) and rewrite the remaining half to apply the dollar-valuing only to the *net* kWh over a billing period. But the Commission is not the General Assembly, and it should refuse the invitation of Messrs. Barnes and Rábago to exceed its lawful authority by imposing a billing-period netting regime in violation of KRS 278.465(4) and 278.466(3).

Moreover, it seems unlikely that Messrs. Barnes and Rábago would have the same position if they believed the Commission would set an NMS-2 compensation rate in excess of the Companies' retail residential energy rates. In contrast to the Companies, which are largely financially indifferent to NMS-2 compensation rates because all customers, not the Companies, will bear the costs for excess energy

[24] Emphasis added.

supplied to the grid by a customer-generator, Messrs. Barnes and Rábago are employed in these proceedings by entities with direct financial ties to the installation of small-scale solar facilities.

Second, the billing-period netting approach Messrs. Barnes and Rábago desire is contrary to the reality of how the electrical system works. Energy produced to the Companies' grid is immediately consumed; there is no large-scale storage on the Companies' electrical system because it is currently prohibitively expensive. Yet a billing-period netting approach pretends this is not true; it engages in the fiction that a customer-generator can produce energy onto the grid at certain times and then withdraw the same energy at other times as though that energy had not been consumed by others in the interim. In other words, it treats the electrical grid as a costless, lossless battery, which it plainly is not, as Mr. Sinclair addresses in his supplemental rebuttal testimony. The previous versions of KRS 278.465 and 278.466 forced the Commission and utilities to engage in this fiction as well, and NMS-1 customers will continue to be treated this way for 25 years after the final order on NMS-2 compensation rates in these proceedings. But the Commission should refuse to pretend for NMS-2 customers that the energy they consume from the grid is not produced in real time and that the energy NMS-2 customers produce to the grid is not consumed in real time. The way to end this fiction is to use the netting approach prescribed by KRS 278.465 and 278.466 and set out in the Companies' NMS-2 tariff sheets.

VI. THE COMMISSION SHOULD REJECT MR. BARNES'S ACCOUNT OPENING, CLOSING, AND NET METERING CREDIT TRANSFER PROPOSALS BECAUSE THEY VIOLATE KRS 278.466(4) AND (6)

Q. Mr. Barnes notes the Commission's June 30, 2021 Order's concerns about account opening and closing policies, and then he "urge[s] the Commission to

establish a general policy that accumulated credits may run with the premises on which they were generated."[25] Is Mr. Barnes's proposed approach permissible under KRS 278.466(4) and (6)?

A. No. "[E]stablish[ing] a general policy that accumulated credits may run with the premises on which they were generated" would be directly contrary to KRS 278.466(4) and (6). Regarding net metering customers with dollar-denominated bill credits, KRS 278.466(4) states, "Excess bill credits *shall not* be transferable between customers or premises."[26] The statute is unambiguous; net metering credits cannot "run with the premises on which they were generated," and they cannot travel with a net metering customer from one premises to another.

Likewise, KRS 278.466(6) states that customers who continue to take net metering service with kWh-netting and credits (i.e., NMS-1 customers) do so under the tariff terms in place for such service when the customer-generator began taking net metering service. The Companies' current NMS tariff provisions state, as they always have, "Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between Customers or locations."[27] This too prevents credits from "running with the premises" as Mr. Barnes proposes.

Q. Mr. Barnes also advocates that "any account that has previously been enrolled in net metering should be automatically enrolled in net metering when a new customer takes service at the same service address without requiring a new

[25] Barnes Supplemental Testimony at 15.
[26] Emphasis added.
[27] Kentucky Utilities Company, P.S.C. No. 19, First Revision of Original Sheet No. 57; Louisville Gas and Electric Company, P.S.C. Electric No. 12, First Revision of Original Sheet No. 57.

interconnection or net metering application."[28] Would you like to comment on Mr. Barnes's proposal?

A. Yes. It is not entirely clear what Mr. Barnes is proposing or why. If he is advocating for net metering credit transfers between customers at the same premise, KRS 278.466(4) and (6) clearly prohibit such a policy, as I discussed above.

If Mr. Barnes is concerned about NMS-1 legacy rights regarding premises that are transferred from one customer to another, such rights are already guaranteed under KRS 278.466(6):

> 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, including the one-to-one (1:1) kilowatt-hour denominated energy credit provided for electricity fed into the grid, *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*.[29]

If what Mr. Barnes intends to address is what the Commission noted it desired to address further in this portion of these proceedings, namely opening and closing accounts for married people, then again it is unclear exactly what he is proposing. Regarding married people's accounts, the Companies' procedures are consistent with what I understand is generally the standard approach for accounts of various kinds involving married people in Kentucky. For example, though I am not at attorney, it is my understanding that one spouse is generally not responsible for the other spouse's credit card debts; likewise, one spouse does not generally have rights to the money in the other spouse's bank account if the account is not joint. Similarly, the Companies

[28] *Id.*
[29] Emphasis added.

do not hold a spouse responsible for an account with the Companies if only the other spouse's name is on the account; neither would any accumulated net metering credits transfer between spouses in a divorce or death event in such a situation. On the other hand, if both spouses are on an account with the Companies—in essence a joint account—then the Companies would seek payment from both spouses for an outstanding balance, just as they would keep net metering credits on the account in a death or divorce situation. In other words, the Companies' marital account opening, closing, and net metering credit transfer policies are symmetrical with regard to payment responsibility and net metering credits, and they align with how accounts for married people work in general. Thus, it is not clear there is a problem or inequity to address regarding such accounts and situations.[30]

Moreover, there is a simple solution to address the Commission's apparent concern regarding net metering credits for married people, one that does not require changing any policies: married net metering customers who do not currently have joint accounts can simply make their existing accounts joint. That would ensure that a spouse who continues to reside at a premise with an eligible electric generating facility would keep accumulated net metering credits after divorce or the death of the other

[30] It is perhaps worth noting that the Commission reviewed a related issue, namely the joint liability of spouses for utility bills, in an administrative case in the mid-1980s. *See Joint Liability of Husband and Wife for Payment of Utility Bills*, Administrative Case No. 276, Order (Ky. PSC Sept. 24, 1984). The Commission ultimately determined not to create a blanket rule regarding the issue:

> After considering the comments as filed, the Commission finds that it is in the best interests of the utility customers to not adopt general regulations at this time but to continue resolving these complaints on a case by case basis. The factual situations that give rise to payment liability problems among family members are virtually infinite, and it is the Commission's opinion that no specific regulation could possibly address even the majority of these problems. Instead, a flexible case by case approach in resolving these complicated situations is often fairer to both the customer and the utility. For these reasons, the Commission will not adopt a specific regulation concerning liability for payment of utility bills at this time.

Id. at 2.

spouse. All that is required is a call to the Companies' customer service department and that the account have no balance owing at the time the other spouse is added. But the Companies do not believe they should determine for married couples whether both spouses will be jointly liable for their utility bills; it is a decision for each couple to make.

But if Mr. Barnes is proposing to broaden the scope of people who can transfer net metering credits to each other, e.g., "from one renter to another with no gap in service," then his proposal again runs afoul of KRS 278.466(4) and (6); net metering credit transfers between customers are statutorily impermissible.

Finally, if Mr. Barnes is concerned that transferring a premise with an eligible electric generating facility requires a new net metering application for the transferee to take net metering service, the Commission's Net Metering Interconnection Guidelines—which are included in the Companies' tariffs—should put an end to that concern.[31] They are clear that a new application is not necessary in such a situation, though written notification of the transfer is required.[32]

VII. CONCLUSION

Q. Mr. Rábago states, "The Commission should aim to produce a methodology for determining net metering compensation rates which is transparent, clear, and accessible to all stakeholders."[33] Do you agree with Mr. Rábago?

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[31] Kentucky Utilities Company, P.S.C. No. 19, Original Sheet No. 57.5; Louisville Gas and Electric Company, P.S.C. Electric No. 12, Original Sheet No. 57.5.

[32] *Id.* ("Customer's generating facility is transferable to other persons or service locations only after notification to Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, Customer, or location, Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, Company will notify Customer in writing and list what must be done to place the facility in compliance.").

[33] *Id.*

A. Yes. Though I disagree with Mr. Rábago on many points, on this point I wholeheartedly agree. The NMS-2 methodology should be "transparent, clear, and accessible to all stakeholders."

I would further ask the Commission to create a clear, repeatable methodology that recognizes that NMS-2 compensation rates must be fair, just, and reasonable to *all* customers, not just net metering customers. The Commission should continue to adhere to its lowest-reasonable-cost approach to ratemaking by limiting itself to considering only genuinely avoidable costs—and the most economical ways to avoid such costs. In other words, it should adhere to *cost*-based ratemaking, not *value*-based ratemaking. What the Companies have proposed regarding NMS-2 in these proceedings—both in their initial application and the methodology articulated by Mr. Sinclair in his supplemental testimony—meets all the criteria of clarity, repeatability, fairness to all customers, and being cost-based. That will serve all customers well and fulfill the Commission's statutory mandate to ensure all customers receive safe and reliable service at the lowest reasonable cost.

Q. Does this conclude your testimony?

A. Yes, it does.

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

RM Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 4th day of August 2021.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

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	)	**CASE NO. 2020-00350**
METERING INFRASTRUCTURE,	)	
APPROVAL OF CERTAIN REGULATORY	)	
AND ACCOUNTING TREATMENTS, AND	)	
ESTABLISHMENT OF A ONE-YEAR	)	
SURCREDIT	)	

SUPPLEMENTAL REBUTTAL TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: August 5, 2021

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. I am the Managing Partner of The Prime Group, LLC. The Prime Group's business address is 2604 Sunningdale Place East, La Grange, Kentucky 40031.

Q. Did you submit direct, rebuttal testimony and supplemental in these proceedings?

A. Yes. I submitted direct testimony, rebuttal testimony, and supplemental testimony on behalf of Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"). My supplemental testimony addressed specific issues as related to the appropriate purchase rates for energy supplied to the grid by customers under the Companies' proposed Net Metering Service 2 ("NMS-2").

Q. What is the purpose of your supplemental rebuttal testimony?

A. The purpose of my supplemental rebuttal testimony is to rebut the supplemental testimonies of Joint Intervenors Mountain Association, Kentucky Solar Energy Society, Kentuckians for the Commonwealth, and Metropolitan Housing Coalition's ("Joint Intervenors'") witness Karl R. Rábago and Kentucky Solar Industries Association, Inc.'s ("KSIA's") witnesses Justin R. Barnes regarding the Companies' proposed net metering schedule NMS-2. Also, I am supporting workpapers for my testimony, which are being filed with my testimony.

Q. Please summarize your supplemental rebuttal testimony.

A. My supplemental rebuttal testimony addresses the following:

- **The Framework for Developing Avoided Costs for Purchased Energy Rates under NMS-2.** Mr. Rábago recommends a framework for calculating the components included in compensation rates for NMS-2 that includes additional externalities. The Commission has a long history of rejecting externalities as an appropriate consideration for setting rates.

- **Avoided Generation Capacity Cost.** Avoided generation capacity cost should be determined based on the Companies' capacity expansion plan and not imported from a foreign jurisdiction and capacity market such as PJM in which the Companies are not members nor in which they participate. Joint Intervenors Witness Rábago recommends importing a value from a meta-analysis and KYSIA Witness Barnes recommends importing a capacity value from PJM, neither of which is based on the Companies' avoided generation capacity costs. Mr. Barnes also makes a number of other errors besides using the inapplicable PJM market components to calculate a compensation rate for solar.

- **Avoided Energy Cost.** The avoided energy cost should be determined based on the Companies' avoided costs. They should not be based on prices from the LG&E PJM Interface, as recommended by Mr. Barnes. The Companies purchase less than 0.02% of its energy requirements from this interface. The prices at this node are generally higher and more volatile than the Companies' marginal energy costs. That is why the Companies make so few economic purchases from the interface. The energy prices at this interface have no bearing on the Companies' avoided costs.

- **Avoided Ancillary Service Cost.** It is extremely unlikely that any ancillary service costs will be avoided by energy supplied to the grid by customer generators. If an ancillary service component is included in the compensation rate for NMS-2 then it should be based on factors included in the Companies' filed ancillary service rates which have been approved by the Federal Energy Regulatory Commission ("FERC"). There is no basis for using ancillary service rates for Kentucky Power that have been approved by the FERC in PJM. KU and LG&E are not Kentucky Power, and the Companies are not members of PJM. The PJM ancillary service rates do not apply to KU and LG&E.

- **Avoided Transmission Capacity Cost**. It is my recommendation that the avoided transmission capacity component should be zero. However, if a transmission component is included in the compensation rate for NMS-2, then it should be based on an analysis of avoided costs. Mr. Barnes proposes a methodology and calculation based on the Companies' embedded costs. Embedded costs cannot be used as a proxy for avoided costs. Using embedded costs to determine avoided costs runs contrary to the Commission's definition of avoided costs.

- **Avoided Distribution Capacity Cost.** It is my recommendation that the avoided distribution capacity component should be zero. However, if a distribution component is included in the compensation rate for NMS-2, then it should be based on an analysis of avoided costs. Mr. Barnes recommends a general methodology that would use embedded costs to determine the component. His recommended approach, which would be based on embedded costs, should be rejected.

- **Avoided Carbon and Environmental Compliance Costs.** It is my recommendation that the avoided carbon and environmental costs component should be zero. Neither Mr. Rábago nor Mr. Barnes proposes a specific rate for this component.

- **Jobs Benefits Credit.** A jobs benefit credit is an externality that should not be included in the compensation rates for NMS-2. Neither Mr. Rábago nor Mr. Barnes proposes a specific rate for this component.

II. FRAMEWORK FOR DEVELOPING COMPENSATION RATES UNDER SCHEDULE NMS-2

Q. Please provide a brief explanation of the avoided costs that the Commission directed the Companies to address in its supplemental testimony.

A. In its Order dated June 30, 2021, in these proceedings, the Commission identified seven avoided cost components along with jobs benefits that should be considered in developing export compensation rates for NMS-2 customers. The avoided costs components identified by the Commission were: (a) avoided energy cost, (b) avoided ancillary service cost, (c) avoided generation capacity cost, (d) avoided transmission capacity cost, (e) avoided distribution capacity cost, (f) avoided carbon cost, and (g) avoided environmental compliance costs. The Commission also identified jobs benefits as a category to be considered. As I explained in my supplemental testimony, the seven avoided costs are ones that may legitimately be considered in developing the compensation rates for energy delivered to the grid by customer-generators under NMS-2. But as I explained in my supplemental testimony, although the cost categories identified in the Commission order are reasonable for the consideration as to avoided costs, the cost under any given category could be determined to have a value of zero. The Companies strongly disagree that a job benefits credit should be included in the determination of avoided costs.

Q. Is there a consensus among the Companies and intervenor witnesses regarding the framework that should be used to develop avoided costs for the NMS-2 compensation rate?

A. No. Mr. Rábago states that "additional avoided cost components should be included within the [Commission's] methodology to produce an even more comprehensive, fair, and reasonable compensation rates." Specifically, Mr. Rábago argues that additional values of solar should be imported wholesale from a meta-analysis of various value-of-solar studies reported by Hayibo & Pearce[1] and from a value-of-solar study produced by the Minnesota Department of Commerce.[2] In addition to the components identified by the Commission, Mr. Rábago would include solar integration costs and health liability.

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[1] Hayibo, Koami Soulemane & Pearce Joshua, "A Review of the Value of Solar Methodology with a Case Study of the U.S. VOS," *Renewable and Sustainable Energy Reviews*, 137(2): 110599 (2021).
[2] Minnesota Department of Commerce, Division of Energy Resources, *Minnesota Value of Solar: Methodology*, April 1, 2014.

Q. Should these other components be considered in the determination of avoided costs?

A. No. They bear no relationship to KU and LG&E's costs and should not be included. These additional components are externalities. The Commission has made it perfectly clear that the Commission should not and cannot consider externalities in setting utility rates. As it has made clear in prior orders, the Commission has no jurisdiction over externalities:

> KRS Chapter 278 creates the Commission as a statutory administrative agency empowered with "exclusive jurisdiction over the regulation of rates and service of utilities." The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service.[3]

Therefore, Mr. Rábago's recommendation that these additional values-of-solar be imported from his meta-studies should be rejected. Health benefits, integration costs, and jobs benefits are externalities, and no amount of rhetorical reframing by Mr. Rábago will transform these "values of solar" into costs that can be avoided by LG&E or KU. A fundamental role of utility regulation is to act as a stand-in for market forces to mitigate monopolistic pricing. Mr. Rábago's approach would flip this role on its head and would insist that the Commission compel customers to pay much higher prices than either the Companies' avoided costs or market prices for solar energy. Only the legislature has the authority to make this kind of decision.

[3] Commission Order in Case No. 2017-00441, dated October 5, 2018, at p. 28

Q. Are various value-of-solar studies reported by Hayibo & Pearce[4] and value-of-solar study produced by the Minnesota Department of Commerce filed in this record?

A. No. And the authors of these studies are not witnesses in these cases. Thus, discovery of the inputs, assumptions and methodologies supporting these studies is very limited. The studies cannot be fully evaluated to determine whether they are objective or have flaws that affect their conclusions.

Q. What about Mr. Rábago's and Mr. Barnes's recommendation that the Commission either include or consider a "jobs credit"?

A. While the Commission has not identified health benefits and integration costs among the categories of "avoided costs" to be considered, it has identified job benefits as a value to be considered. It should be emphasized that any value for jobs creation would also represent an externality to utility costs. Furthermore, a jobs benefit credit should not be determined based on values from a meta-analysis, as suggested by Mr. Rábago. Because jobs creation does not affect the Companies' cost of providing service, an avoided cost component for jobs creation should not be included as an avoided cost. Furthermore, it needs to be emphasized that compensating net metering customers for a jobs credit is in no way comparable to offering Economic Development Rates ("EDRs"). New loads served under EDRs have the effect of spreading the Companies' existing fixed costs over a larger sales volume, thus benefiting all

[4] Hayibo, Koami Soulemane & Pearce Joshua, "A Review of the Value of Solar Methodology with a Case Study of the U.S. VOS," *Renewable and Sustainable Energy Reviews*, 137(2): 110599 (2021).

customers. Providing a jobs credit to net metering customers does not result in spreading fixed costs over a larger sales volume, but simply increases utility rates to non-participating customers, thereby creating subsidies. Because there is no cost-of-service basis for a jobs credit, any amount added to the NMS-2 compensation rates for "jobs" would be arbitrary and not constrained by any sort of limiting principle. The Commission Order in Case No. 327 established strict guidelines for offering EDRs designed to ensure that the utility's existing customers would benefit from serving new customers on the system, ensuring specifically that EDR customers would make a contribution towards the recovery of the Companies' fixed costs. Including an arbitrary jobs component is incongruous with the principles set forth in the Commission's Order in Case No. 327, which required the marginal revenue from an economic development customer to exceed the marginal cost of serving the new customer. As construed by Mr. Rábago, a job benefits credit provided to NMS-2 customers would not consider the Companies' marginal or avoided cost. It would be arbitrary and presumably based on a meta-analysis.

III. AVOIDED GENERATION CAPACITY COST

Q. What avoided generation capacity cost does Mr. Rábago recommend?

A. Mr. Rábago does not recommend a specific avoided generation capacity cost. Despite all the information available to Mr. Rábago, including the mountains of data provided by the Companies in the current proceeding regarding their generation resources, Mr. Rábago claims that not enough data were provided for him to calculate avoided generation capacity. Ultimately, Mr. Rábago recommends that the Commission rely on values determined from a meta-analysis. But he never indicates what those values are, nor does he provide any type of calculation.

Q. What avoided generation capacity cost does Mr. Barnes recommend?

A. Mr. Barnes recommends using the net Cost of New Entry ("CONE") from PJM to calculate avoided capacity cost.

Q. Is there anything wrong with this approach?

A. Yes. Neither KU nor LG&E is a member of PJM. The net CONE rate from PJM has no bearing on the Companies' costs. Net CONE is a market construct developed as part of the market design for the PJM generation capacity auction. KU and LG&E are not members of the PJM market and do not participate in PJM auctions. The PJM net CONE is a filed rate for PJM and only applies to PJM members and does not correspond to any filed rate that is applicable to KU or LG&E. It would be inappropriate to import an element from a capacity market in which the Companies do not participate and that has not been demonstrated to be applicable to the Companies' operations.

Q. How does net CONE come into play in PJM?

A. It rarely does. Net CONE is the cost of a new generation resource entry in PJM netted against the expected revenue for the resource from PJM's Energy and Ancillary Services market. The minimum price that a participant in the PJM capacity auction can submit a bid is determined by the Minimum Offer Price Rule ("MOPR"). MOPR is designed to ensure that new resources are offering competitively into PJM's capacity auction and not artificially altering prices in the market by exercising market power. A resource's MOPR value is determined by either the net CONE or net Avoidable Cost Rate, with net CONE applying to new resources and net Avoided Cost Rate ("ACR") corresponding to the net annual operating cost of existing facilities. Obviously, capacity is only purchased in the PJM capacity market when there is a need. An entity that has no capacity need would not purchase capacity in the PJM capacity market.[5] Furthermore, because there is currently an abundance of existing generation capacity in the PJM capacity market, there is very little need for New Entry capacity. In the Base Residual Auction for the 2022/2023 capacity auction in PJM, out of a total capacity of 145,164 MW clearing the capacity market, only 513 MW of New Entry MOPR cleared the market.[6] Thus, only 0.35% of the capacity auction in PJM was made up of New Entry capacity subject to net CONE. As this shows, virtually none of the capacity that cleared the PJM auction was subject to net CONE. Therefore, requiring net CONE as an applicable capacity value for energy supplied to the grid by customer-generations under NMS-2 would grossly overstate the current market value of generation capacity, even in the PJM capacity market.

Q. Do KU and LG&E currently have a generation capacity need?

A. No, not currently. As discussed in Mr. Sinclair's supplemental testimony, the Companies' 2021 Business Plan ("2021 BP") assumed that Mill Creek Unit 1 would

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[5] While all PJM members are required to participate in the capacity market, they are not required to purchase capacity that they do not need.

[6] See http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023-bra-mopr-results.ashx.

be retired without replacement in 2024, and Mill Creek Unit 2 ("MC2") and Brown Unit 3 ("BR3") would be retired in 2028. Based on these assumptions, the Companies would not need additional generation capacity until 2028, and then only a relatively small amount of capacity. But the retirements of MC2 and BR3 in 2028 are uncertain. In the absence of stricter environmental regulations, these units would not be retired until at least the end of their depreciable lives. In the absence of new environmental regulations that require the retirements of these generating units, the Companies would not need additional generation capacity until at least 2034. Therefore, at the earliest, the Companies will not need generation capacity until 2028 and just as likely not until 2034.

Q. Considering that the Companies do not have a current need for capacity, then is it appropriate to use net CONE as an avoided capacity value?

A. No. KU and LG&E do not have a capacity need until between 2029 and 2034; therefore, using the net CONE value is inappropriate from any point of view. Just as the net CONE rate does not apply to capacity value in PJM, it does not apply for KU and LG&E. There are much less costly alternatives for generation capacity than the net CONE rate, even in PJM. There is little or no need for additional capacity in PJM; therefore, the net CONE rate has no significance, not even in PJM. This raises the serious concern of why the Companies' customers should be required to pay the net CONE price for energy supplied by customer-generators under NMS-2 when utilities in PJM generally do not pay the MOPR or the net CONE rate for capacity—and when the Companies are not PJM members and are therefore not subject to such pricing at all.

Q. Then how should avoided generation capacity costs be determined for KU and LG&E?

A. Avoided generation capacity costs should be determined based on the *Companies' avoided costs*, not based on a meaningless and generally unused market construct in PJM, a market organization of which neither KU nor LG&E is a member. Mr. Barnes's recommendation to use the PJM net CONE rate (and not even the actual capacity bid prices in PJM or the net CONE Rate actually utilized for new market entries) is nothing more than a way to maximize the price that the Companies' customers would pay for generation supplied to the grid under NMS-2. What is relevant is the Companies' avoided costs, not a component from a foreign market construct that has no relevance to the Companies' costs and that has little or no relevance even in PJM. Clearly, an element of a competitive market design for a capacity market that the Companies do not participate plainly cannot be used to determine the Companies' avoided generation capacity costs. The Companies' own avoided costs must be utilized. It would be irresponsible for the Companies to make capacity payments based on a value of capacity that it will not need for years to come.

Q. Virtually all of the customer-generators on the Companies' system are fixed-tilt solar facilities. What is the current avoided capacity value of energy purchased from new net metering customers with fixed-tilt solar facilities?

A. Currently, the capacity value is zero. The Companies currently have sufficient generation capacity to meet their customers' needs. As explained earlier, KU and

LG&E do not have a need for additional capacity until 2028 at the earliest and just as likely not until 2034. Thus, energy supplied from new net metering customers does not provide any capacity value.

If the Companies could depend on the customer-generators to supply firm capacity over a sufficiently long period of time (such as 20 years or more), then receiving energy from customer-generators could theoretically permit the Companies to avoid capacity.[7] As I have explained, because solar generation is intermittent, any energy supplied to the grid from solar panels is fundamentally non-firm energy. But additionally, customers may choose not to perform maintenance on their solar panels and choose not to replace components of their systems when they fail, or property owners – particularly new property owners – could find solar panels to be unattractive and remove them for aesthetic reasons.

As I explained at the earlier hearing in these proceedings, the avoided cost of solar capacity is solar capacity. The Companies will submit an Integrated Resource Plan ("IRP") later this year. This IRP will certainly evaluate greater reliance on solar generation. Since the Companies' 2018 IRP was prepared, the cost of solar generation has decreased considerably and is expected to continue to go down as new photovoltaic technologies are introduced. Therefore, as the Companies integrate more renewable resources in their supply mix, the capacity avoided will be solar capacity.

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[7] As a practical matter, it is unlikely that energy supplied from customer-generators could ever be sufficient in Kentucky to avoid or defer generation capacity. Net metering is capped at 1% of system peak load and has not been that significant in Kentucky, given factors such as cloud cover, demographics, etc.

The Companies have a definitive benchmark for the value of fixed-tilt solar capacity. The Companies recently entered into a solar Purchased Power Agreement ("Solar PPA") contract with Rhudes Creek Solar, LLC, to purchase energy over a 20-year period from a solar facility at a total cost, including both energy and capacity, of \$0.02782 per kWh.[8] This price is not out of line with the price for solar energy and capacity of other Solar PPAs. There is no reason why the Companies and their non-net metering customers should be required to pay the PJM CONE rate for energy supplied to the grid by customer-generators under NMS-2, as recommended by Mr. Barnes, when the Companies can purchase energy and capacity from solar farms at a cost of \$0.02782/kWh.

Mr. Barnes's proposal flies in the face of sound economics. His proposal is a results-oriented scheme designed to maximize the value received by customer-generators. It is as if Mr. Barnes surveyed the landscape looking for the highest generation capacity value he could find, ultimately settling on the CONE value used in the PJM capacity market, even though it has no relevance or applicability to the Companies' avoided costs.

Q. Assuming that customer-generators can be depended on to provide energy over a sufficiently long period of time, how can the avoided capacity cost be determined?

[8] The purchased power Agreement to purchase renewable energy from Rhudes Creek Solar, LLC, was filed with the Commission in Case No. 2020-00016 and is attached to the Rebuttal Testimony of Robert M. Conroy as Rebuttal Exhibit RMC-1 in these proceedings. This agreement is discussed in Mr. Conroy's Rebuttal Testimony.

A. As I have explained, the only capacity that fixed-tilt solar energy supplied from customer-generators could avoid is the cost of fixed-tilt solar. This is an apples-to-apples comparison. We have a reliable benchmark for the current value of fixed-tilt solar capacity and energy. It is $0.02782 per kWh, as reflected in the PPA with Rhudes Creek Solar, LLC. But the Companies do not currently need additional generation capacity. As explained earlier, the Companies do not need additional generation capacity until at least 2028. Therefore, the value of solar generation capacity in 2028 must be discounted to 2021 dollars. Furthermore, the value must be levelized over a 20-year presumed contract term, with zero value for the year 2021-2027, when the Companies have no capacity need. It would be inappropriate for the Companies to attribute a value for capacity supplied during years when the Companies have no capacity need. In calculating avoided generation capacity, it is appropriate to attribute zero capacity value during years when there will be sufficient generation capacity to meet customers' needs.

Q. Is capacity supplied from solar facilities comparable in value to a conventional combustion turbine or combined-cycle combustion turbine?

A. No. The capacity value of fixed-tilt solar facilities supplied by a customer-generator is comparable to the capacity value of fixed-tilt solar capacity that the Company would otherwise purchase through a solar PPA. Based on the Companies' current planning scenarios regarding their future resource needs, solar generation will be an important component of their planned generation resources. That cost is $0.00181/kWh, based on the Rhudes Creek Solar PPA. While solar facilities will certainly be a key technology for meeting future electric energy requirements, they are not, by themselves, comparable in value to a combustion turbine or combined-cycle combustion turbine. A combustion turbine and combined-cycle combustion turbine can be called upon to supply capacity essentially 8,760 hours per year. This is clearly not the case with solar facilities. Solar generation is intermittent and will only supply energy during daylight hours, and then only at full capacity when the sun is not obstructed by clouds. To have a capacity value comparable to a combustion turbine or combined-cycle generating unit, solar must be combined with long-duration energy storage (which is not generally available today). Customer-generators are simply not providing capacity that is equivalent in value to a combustion turbine or combine-cycle combustion. Frankly, it is disingenuous for Mr. Barnes to suggest that solar energy is in any way comparable to the value of these conventional generation technologies.

Q. Are there other problems with Mr. Barnes's recommended generation capacity cost?

A. Yes, there are several problems besides ignoring the Companies' own avoided costs and importing irrelevant and inapplicable CONE values from the PJM Capacity Market. A critical error that Mr. Barnes made was that he failed to perform a present value and fixed cost levelization calculation of the capacity cost based on the time frame when the Companies will actually need capacity, which at the earliest will not occur until 2028. This is a serious error on Mr. Barnes's part, significantly overstating the capacity value. Anyone involved in utility system planning would understand that present value calculations must be performed on future expenditures.

Q. Please explain the step that Mr. Barnes failed to perform in his calculation of avoided generation capacity cost.

A. As I mentioned earlier, at the earliest the Companies will not need additional generation capacity until possibly 2028. Therefore, any future avoided capacity costs will not be realized until 2028 at the earliest. If a levelized avoided generation capacity cost is to be provided beginning in 2022, then future avoided costs must be discounted to a present value. Those present value avoided costs must then be levelized over a reasonable time frame when a customer-generation would provide service, which the Companies are assuming is a 20-year period.

Q. Please describe what is meant by the term "levelized."

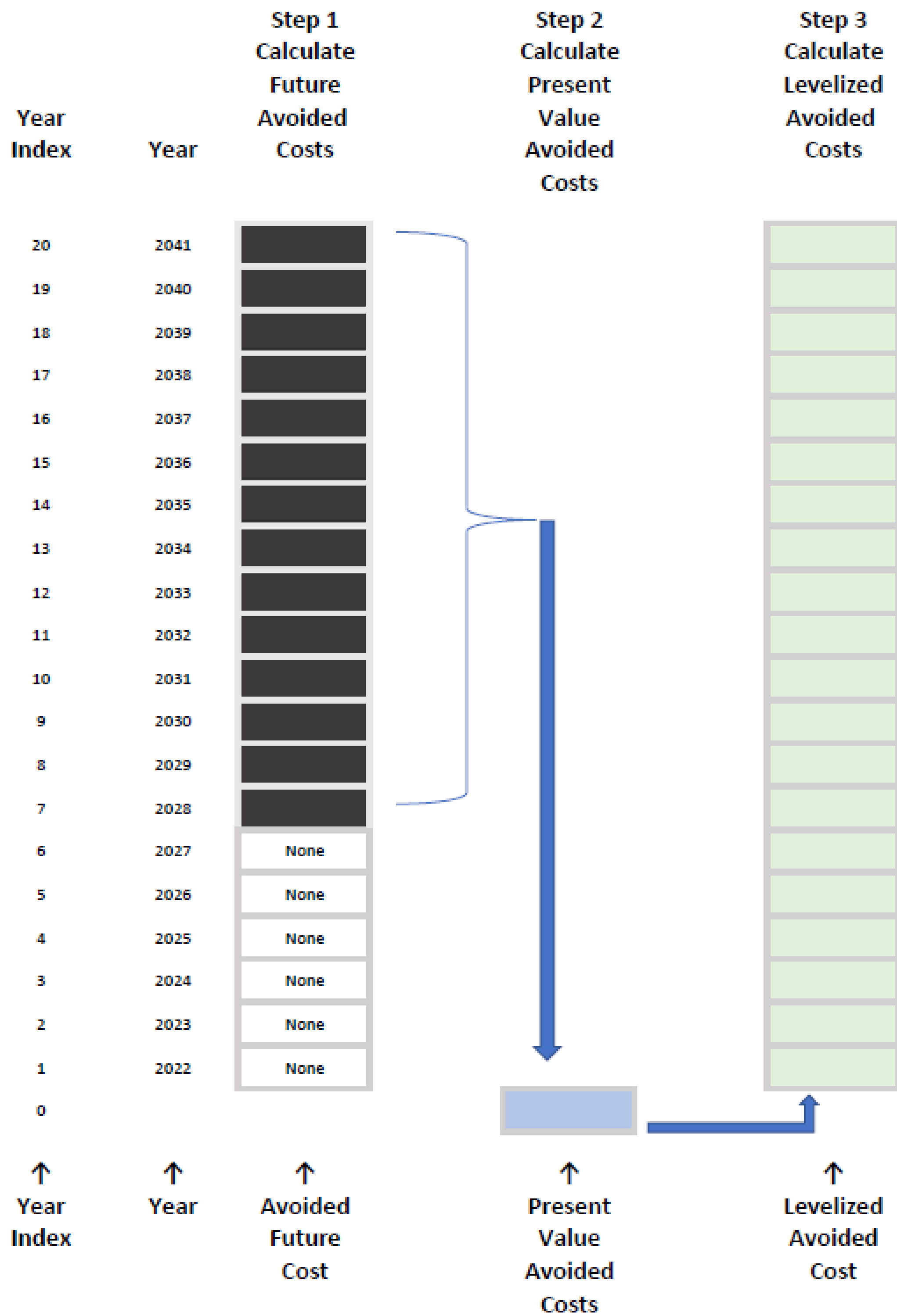
A. What is meant by levelized is to calculate a levelized equal payment amount that is essentially what is used in calculating a loan payment of the conventional home mortgage. It involves applying a capital recovery factor to the present value avoided costs. Therefore, calculating an avoided generation capacity cost involves the following three steps:

- Step 1: calculate future avoided costs that would occur when the Companies actually have a need for additional planned capacity, which for KU and LG&E will not occur until 2028 at the earliest;
- Step 2: calculate the present value of the avoided capacity costs determined in the first step; and

- Step 3: levelize (annuitize) the present value avoided costs over a reasonable time frame. Figure 1 on the following page illustrates this three-step process.

FIGURE 1

Steps For Calculating Avoided Cost Rates



Q. In developing his recommended avoided generation capacity cost, did Mr. Barnes consider the fact that the Companies' do not currently need additional generation capacity?

A. No, he did not. He ignored it. In determining avoided generation capacity cost, Mr. Barnes assumed that the Companies have a current need for additional generation capacity, which is clearly incorrect. At the very earliest, the Companies will not have a need for additional generation capacity until 2028, and just as likely not until 2034. In terms of the steps shown in Figure 1, Mr. Barnes omits all three steps. Furthermore, as explained earlier, he makes the untenable assumption that the energy supplied by customer-generators with solar panels could avoid a combined cycle combustion turbine. The only capacity that the energy supplied by customer-generators operating solar panels could possibly avoid would be the solar capacity planned by the Companies. It is unrealistic to believe that energy supplied by customer-generators operating fixed-tilt solar facilities could avoid any combined-cycle or simple-cycle combustion turbine capacity that the Companies may need. Solar generation is simply not comparable to combustion turbine capacity, which is available anytime that it is called upon.

Q. Are there other problems with Mr. Barnes's approach to calculating the avoided generation capacity component?

A. Yes. Mr. Barnes relied extensively on the Loss of Load Probability (LOLP) calculations used in the Companies' embedded cost of service study to determine the effective solar contribution. The problem here is that in its Order dated June 30, 2021, in these proceedings, the Commission rejected the LOLP methodology, stating that the "Commission concludes that LOLP methodology raises significant questions regarding reliability due to the significant quantity of data inputs, most of which are estimated forecasts."[9] Because the Commission has rejected the LOLP model for use in the Companies' cost of service studies and in developing sales rates, the LOLP model cannot be used to allocate avoided capacity costs. If the LOLP methodology is inadequate for the allocation of fixed embedded costs, then it is equally inadequate for the allocation of avoided generation fixed costs.

Q. Are there other problems with Mr. Barnes's calculation of the avoided generation capacity component?

A. Yes. In calculating the LOLP weighting of solar generation, Mr. Barnes incorrectly assumes that all energy generated by customer-owned solar panels will be supplied to the grid. In his supplemental testimony, Mr. Barnes recommends that "the effective solar capacity determination be based on a representative solar production profile (e.g., using PVWatts) weighted according to hourly LOLP where hourly LOLPs are translated to a percentage of total LOLP over the entire year."[10] It is important to understand that PVWatts is a tool to estimate solar energy generation. It does not estimate the energy consumed by customers nor does it estimate solar generation net

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[9] Case No. 2020-00359, Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates (Ky. PSC Jun. 30, 2021) at p. 32.
[10] Case Nos. 2020-00349 and 202-00350, Supplemental Testimony Justin R. Barnes, at pp. 8-9.

of customer usage.[11] Obviously, not all of output from net metering customers' solar panels is supplied to the grid. A high percentage of the energy generated from net metering customers' solar panels will be used to supply their own energy needs, with only excess generation supplied to the grid. According to the Solar Energy Industries Association, 60% to 80% of the energy generated by customer-generators' solar panels is consumed by the customers to meet their own energy needs such as running their air-conditioners, refrigerators, etc.[12] Yet, Mr. Barnes incorrectly assumes that *all* of the customer-generators' energy will be supplied to the grid. This assumption significantly overstates the LOLP weighting performed by Mr. Barnes. This is clearly improper considering that Mr. Barnes is proposing that these costs be used to determine the compensation rate for the energy that customer-generators under NMS-2 *supply to the grid*.

Additionally, the solar generation data that Mr. Barnes created using PVWatts do not match either empirical data from the Companies' own net metering customers which were provided to KSIA in data responses or data published by National Renewable Energy Laboratory. The data created by Mr. Barnes resulted in a capacity factor of 18.2% compared to a capacity factor of 16.5% estimated by NREL.[13] This

[11] According to NREL, "PVWatts® Calculator is a web application developed by the National Renewable Energy Laboratory (NREL) that *estimates the electricity production of a grid-connected roof- or ground-mounted photovoltaic system based on a few simple inputs*." (Emphasis supplied.) See https://pvwatts.nrel.gov/.

[12] *See* https://www.seia.org/initiatives/net-metering ("On average, only 20-40% of a solar energy system's output ever goes into the grid, and this exported solar electricity serves nearby customers' loads.").

[13] See https://atb-archive.nrel.gov/electricity/2020/data.php.

issue is also addressed in Mr. Sinclair's supplemental rebuttal testimony.

Furthermore, Mr. Barnes failed to provide the assumptions used to develop his hourly solar production data. For example, Mr. Barnes does not provide any insight into how he translated the Companies' hourly load forecasts, which presupposed normalized weather data, into hourly solar generation. His workpapers, specifically the tab labeled "Solar Profile 1 kW-AC" show only entered values. He provides no details as to how the entered values were calculated. As they stand, the solar production data used in his LOLP weighting is an impenetrable black box.

Q. What is your recommendation regarding avoided generation capacity costs?

A. Because of the intermittency and inherent non-firmness of solar generation, which makes up virtually all net-metering facilities located in the Companies' service territories, I continue to recommend that the avoided generation capacity component for NMS-2 should be zero. At a *maximum*, the avoided generation capacity cost component should be \$0.00181/kWh for KU and \$0.00181/kWh for LG&E., discussed in my Supplemental Testimony.

IV. AVOIDED ENERGY COST

Q. What do witnesses Rábago and Barnes recommend for an avoided energy cost?

A. Mr. Rábago does not recommend a specific dollar value for avoided energy cost, nor does he address the methodology that should be used to determine avoided energy cost. Although he does not provide a dollar value for avoided energy costs, Mr. Barnes states without any support other than his judgment that the "LG&E PJM interface appears to be the best fit."[14] He goes on to acknowledge that "this may not equate to the Companies' marginal costs of generation exactly, but interface pricing represents the value of substitute energy from either a purchase or sale standpoint."[15]

Q. Are prices at the LG&E PJM Interface the best fit?

A. No. The LG&E PJM Interface, which is now called the PJM South Real-Time Interface Point, is the default pricing point for transactions at the southern border of PJM. The interface comprises eleven generator buses and eleven pricing nodes, ranging from northern Indiana, across Kentucky and Tennessee, and through North Carolina. PJM assigns weightings to each pricing node to create an aggregate interface LMP. Bus ties for two generating stations in the LGE/KU fleet are included in the aggregate interface market price, Ghent and Brown. The combined weighting for the Ghent and Brown bus ties represent less than 7% (Ghent 5.8% and Brown 1%) of the load flow capability of the interface.

An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. It is a market interface through which energy sales and purchases can flow 1,000 miles or more either north or south through the Midwest. The prices on the interface are much more volatile than the Companies' energy costs and prices are generally higher than the Companies' marginal energy costs. The Companies will make economic purchases on the interface only when the price at the interface is lower than the Companies'

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[14] *Id.*, at p. 7.
[15] *Id.*

marginal running cost, which is rare.

KU and LG&E purchase very little of their energy requirements from this interface, and typically only during a limited number of hours when it is economical to do so. During the last three calendar years, the Companies' annual energy purchases from the LG&E PJM interface made up only 0.02% of the Companies' annual native load energy requirements. During the calendar year 2018, the Companies did not purchase *any* energy from the LG&E PJM Interface. Most of the energy supplied to meet the Companies' native load requirements is generated from the Companies' own generation resources. The following table (TABLE 1) compares the purchases made by the Companies from the LG&E PJM Interface to the Companies' total native load requirements over the last three years:

TABLE 1

Year	Companies' Annual Energy Purchased from LG&E PJM Interface (GWH)	Companies' Annual Native Load Requirements (GWH)	Percentage of Total (%)
2018	0	33,305	0.00%
2019	5.5	33,184	0.02%
2020	10.1	30,699	0.03%
3-Yr Total	15.6	99,188	0.02%

Considering the insignificant amount of energy that the Companies purchase at the LG&E PLM Interface, there is no reasonable basis to assert that the prices at this interface have any bearing on the Companies' avoided costs. The prices cleared on this interface are generally higher than the Companies' energy costs, they are more volatile than the Companies' energy costs, and they bear no relationship to the Companies' avoided costs. Therefore, the prices cleared at the LG&E PJM interface should not be used as a measure of KU and LG&E's avoided energy costs.

Q. For the 12 months ended December 31, 2020, how did the Companies' actual marginal energy prices compare to the prices at the LG&E PJM Interface?

A. The Companies' average hourly marginal energy price was $18.02 per MWH during 2020. The average hourly price at the LG&E PJM Interface was $20.30 during 2020. Therefore, the hourly price at PJM South was on average 13% higher than the Companies' marginal energy cost. But the hourly energy price at the LG&E PJM Interface was significantly more volatile than the Companies' marginal energy cost during 2020. In statistics, the standard deviation is a measure of the variation or dispersion in data about the mean. Standard deviation is the most commonly used measure for the volatility in a data set. For the 12 months ended December 31, 2020, the standard deviation of the Companies hourly marginal energy costs was 2.19. During this same period, the standard deviation of the hourly prices at the LG&E PJM Interface was 11.66. This means that the hourly prices the LG&E PJM Interface had a 5.3 times greater dispersion about the mean than the Companies' hourly marginal costs. In plain English, the hourly prices at PJM South were 5.3 times more volatile than the Companies' hourly marginal costs. The problem with adopting Mr. Barnes's recommendation can be illustrated in the graphs shown on the following pages, depicting the hourly price variations at PJM South compared to the Companies' marginal energy costs for four summer days during the four summer months of June through September. Graph 1 is a comparison for June 3, 2020; Graph 2 is a comparison for July 24, 2020; Graph 3 is a comparison for August 13, 2020; and Graph 4 is a comparison September 9, 2020. These graphs are for four days that exhibited high, but not uncharacteristically high, price volatility at the LG&E PJM Interface. The following table (Table 2) shows the average price and standard deviation at the LG&E PJM Interface compared to the average cost and standard for the Companies' marginal energy cost for these four summer days:

TABLE 2

	Companies' Marginal Cost		**LG&E PJM Interface**	
Date	**Avg. Price**	**Std. Dev.**	**Avg Cost**	**Std. Dev.**
06/03/2020	$17.32/MWH	3.4770	$34.33/MWH	39.8324
07/24/2020	$18.55/MWH	1.0347	$27.18/MWH	19.4354
08/13/2020	$18.80/MWH	0.7802	$33.36/MWH	22.4732
09/09/2020	$17.40/MWH	2.2123	$33.44/MWH	20.8881

As can be seen from this table and the following graphs, prices at the LG&E PJM Interface trend much higher and are far more volatile than the Companies' hourly marginal cost. Mr. Sinclair provides additional comparative analyses between the Companies' marginal costs and price at the LG&E PJM Interface in his supplemental rebuttal testimony.

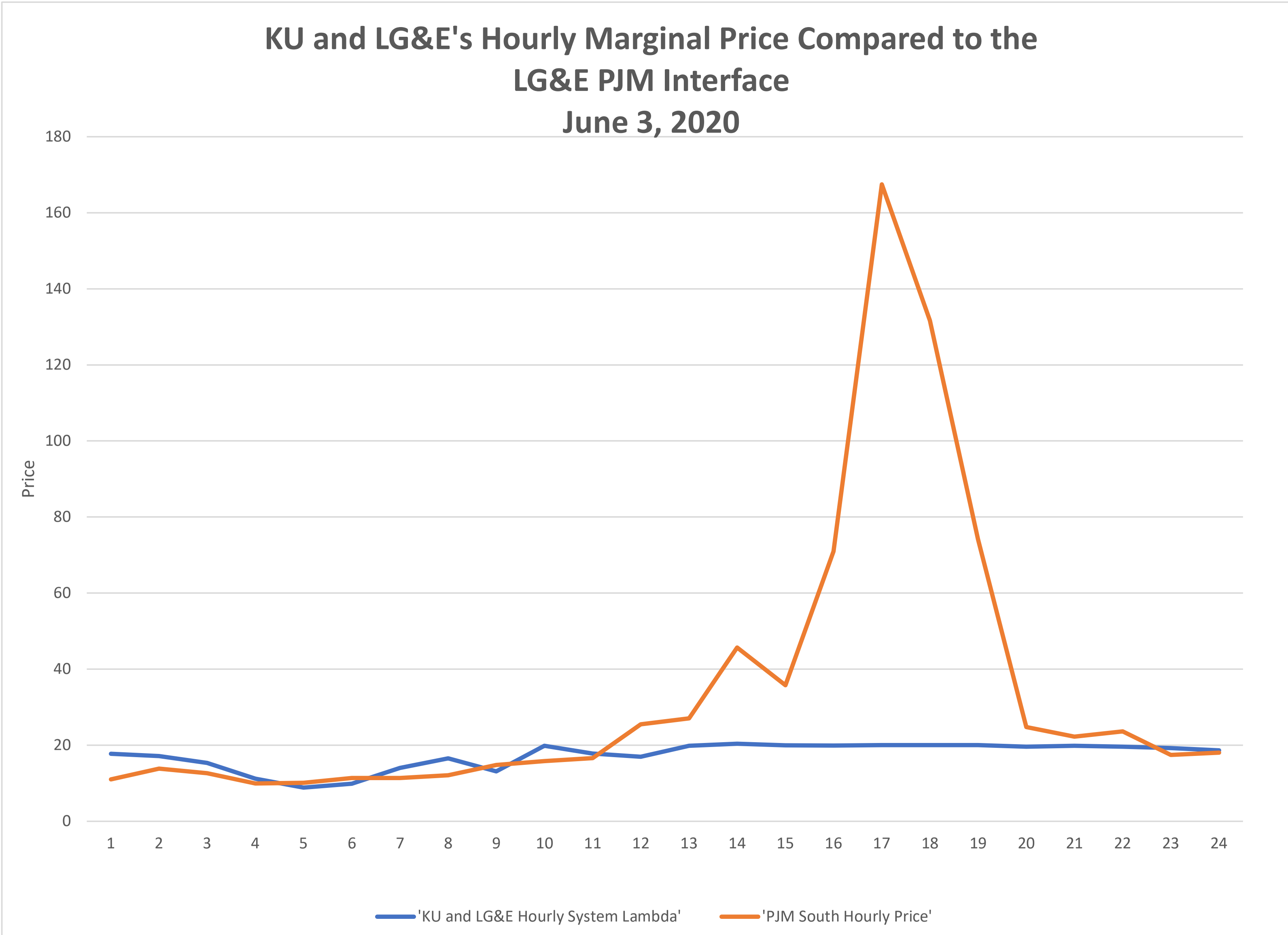
Q. Does this explain why the Companies purchase so little energy from the LG&E PJM Interface?

A. Yes. Most of the time it is far less costly for the Companies to generate the energy themselves rather than purchase energy on the PJM Interface. This underscores the point that Mr. Barnes is proposing an overstated and highly volatile index to calculate avoided energy costs.

Q. What avoided cost should be used for KU and LG&E?

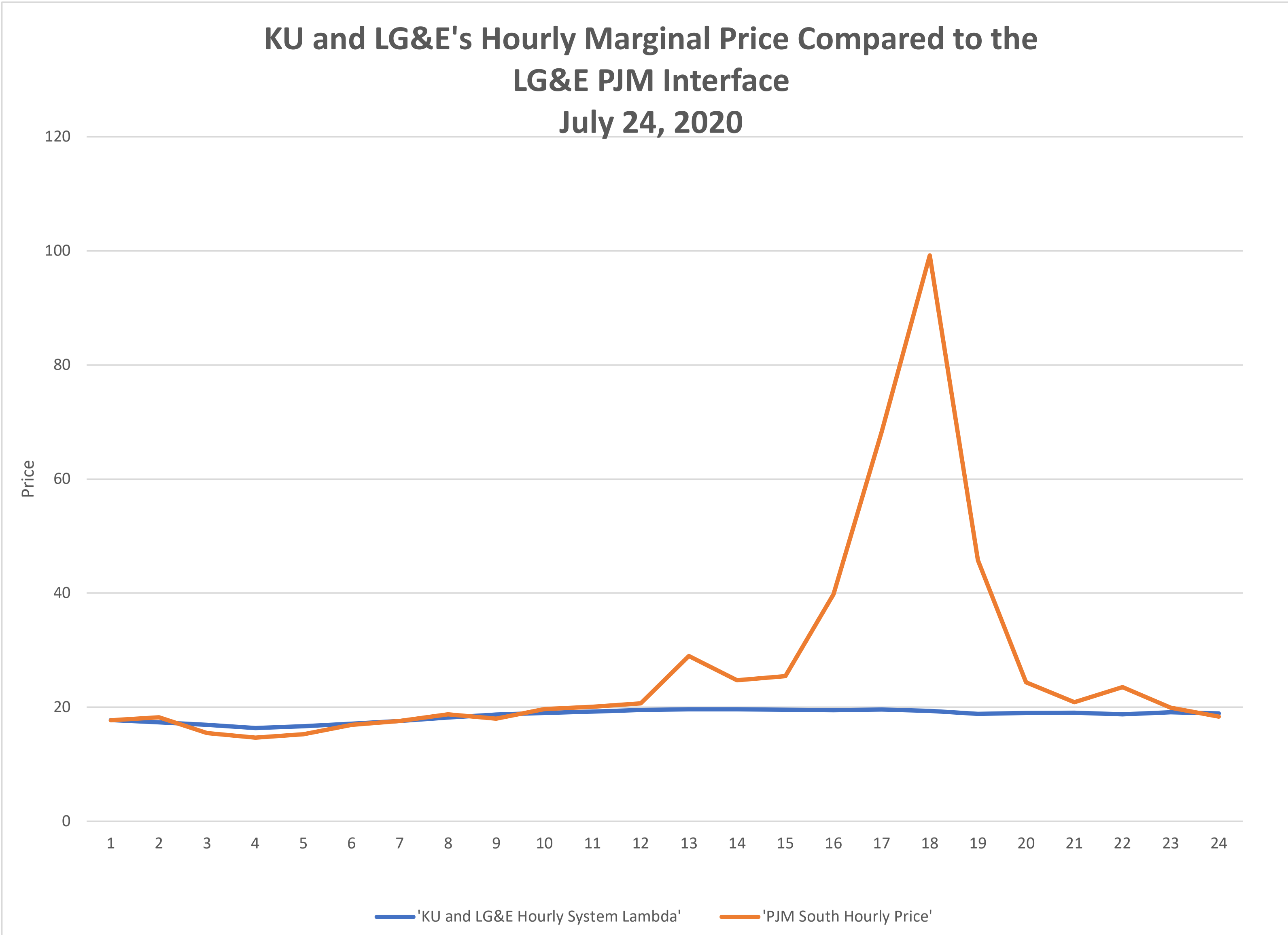
A. The Companies' own avoided energy costs, as addressed in Mr. Sinclair's Supplemental Testimony, should be used to determine the avoided cost component for NMS-2, and not the energy price at the LG&E PJM interface.

GRAPH 1

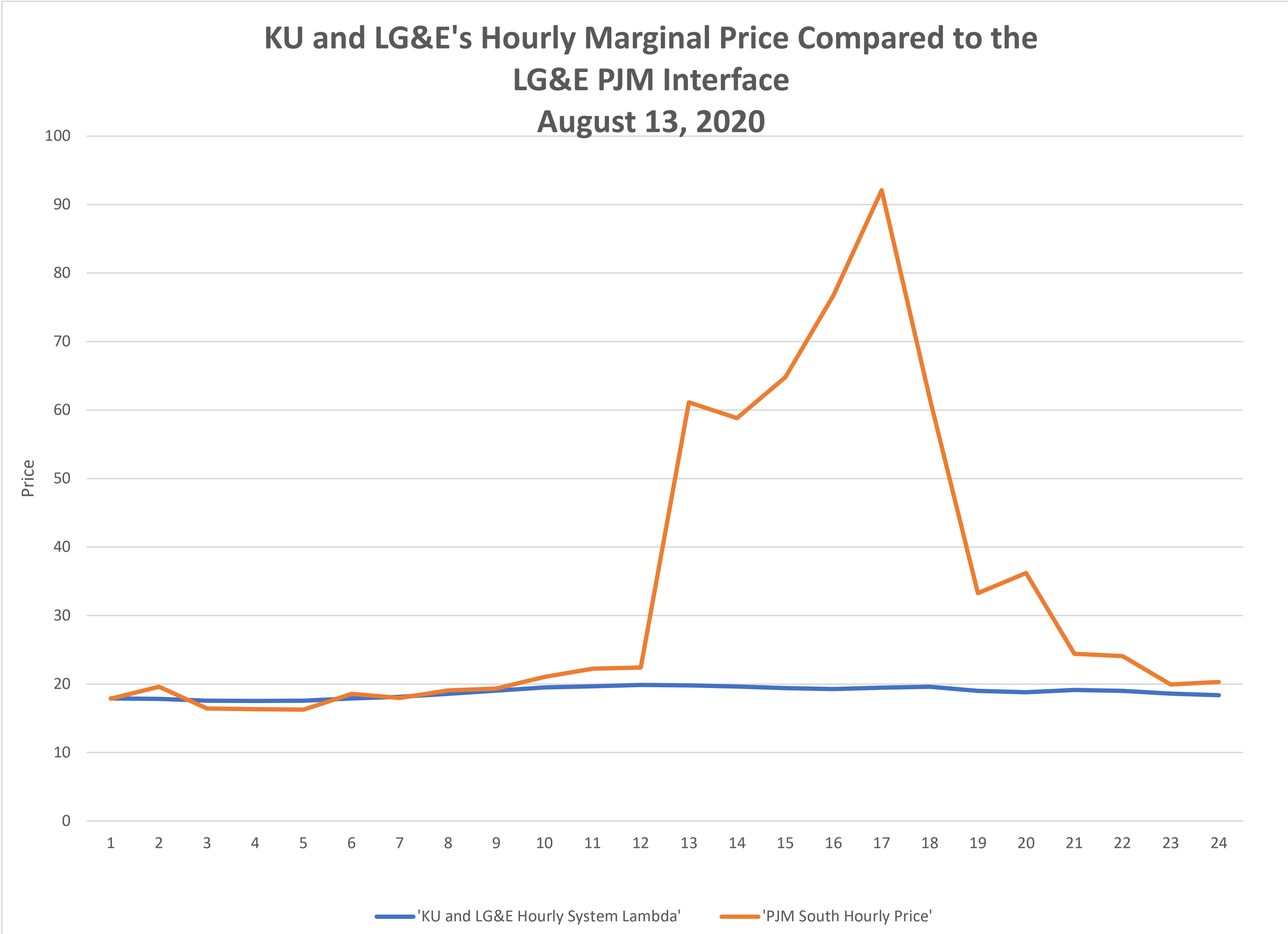


KU and LG&E's Hourly Marginal Price Compared to the
LG&E PJM Interface
June 3, 2020
Price
180
160
140
120
100
80
60
40
20
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
'KU and LG&E Hourly System Lambda'
'PJM South Hourly Price'

GRAPH 2

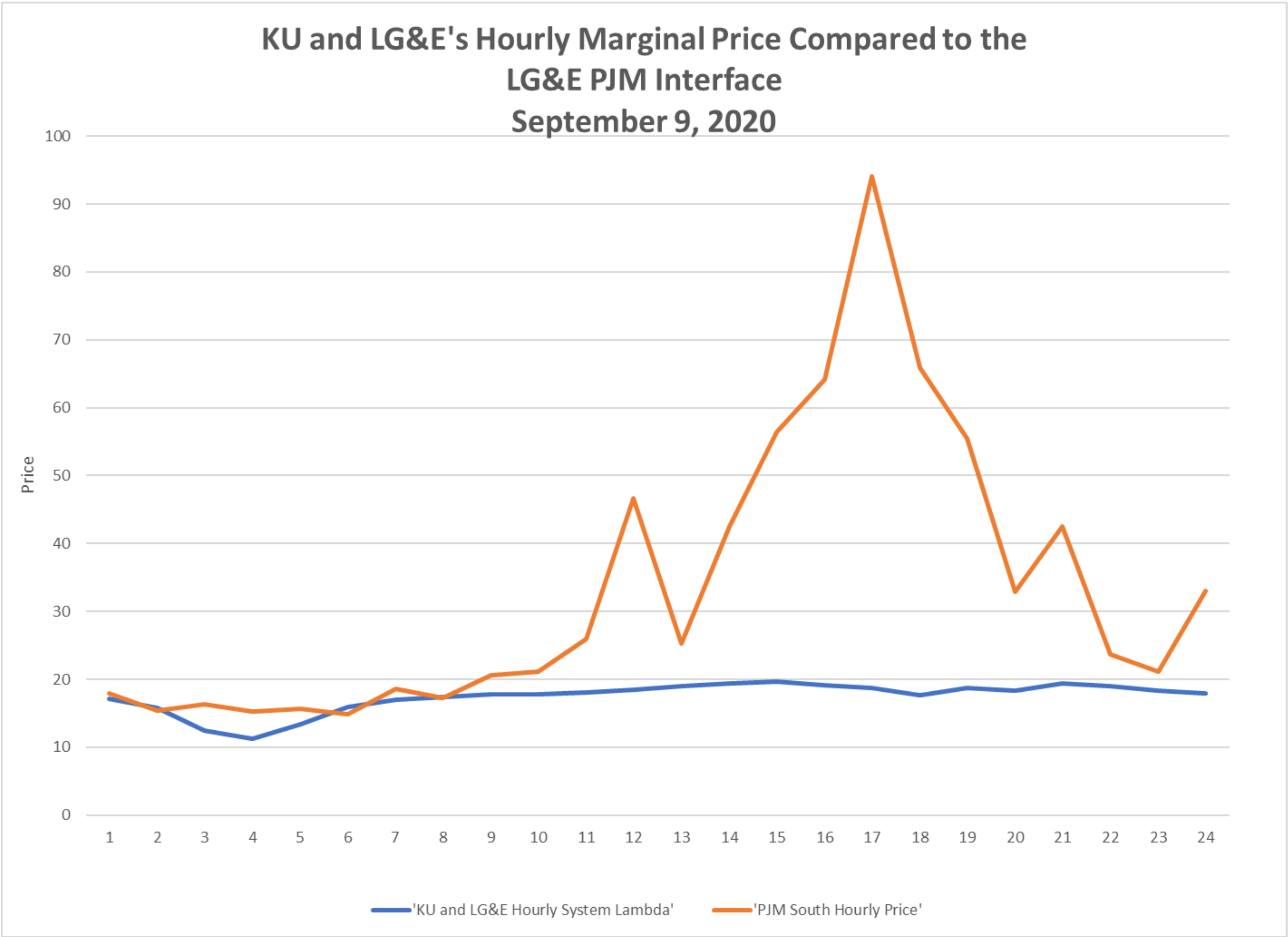

KU and LG&E's Hourly Marginal Price Compared to the
LG&E PJM Interface
July 24, 2020
Price
120
100
80
60
40
20
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
'KU and LG&E Hourly System Lambda'
'PJM South Hourly Price'

GRAPH 3



KU and LG&E's Hourly Marginal Price Compared to the
LG&E PJM Interface
August 13, 2020
Price
100
90
80
70
60
50
40
30
20
10
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
'KU and LG&E Hourly System Lambda'
'PJM South Hourly Price'

GRAPH 4


KU and LG&E's Hourly Marginal Price Compared to the LG&E PJM Interface
September 9, 2020
Price
100
90
80
70
60
50
40
30
20
10
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
'KU and LG&E Hourly System Lambda'
'PJM South Hourly Price'

V. AVOIDED ANCILLARY SERVICE COST

Q. What do witnesses Rábago and Barnes recommend for an avoided ancillary services cost?

A. Mr. Rábago does not address avoided ancillary services costs.[16] Although he does not provide a dollar value for avoided ancillary services cost, Mr. Barnes contends that "the PJM pricing used for the Kentucky Power Company could be used as a reasonable proxy for the Companies' avoided ancillary service costs as it represents a market-based measure for the cost of these services."

Q. Is the PJM pricing of ancillary services used for Kentucky Power Company reasonable?

A. No, not at all. The PJM ancillary service rates used by Kentucky Power Company are the filed rates that have been approved by FERC for members of PJM. Again, neither KU nor LG&E is a member of PJM. The filed ancillary services rates for PJM are not based on KU and LG&E's costs. FERC has not approved the PJM ancillary services rates for KU and LG&E. PJM's ancillary services rates do not apply to the Companies. It is highly inappropriate, and most likely in violation of the filed rate doctrine, to apply the filed ancillary service rates of another utility (or group of utilities) to KU and LG&E, which have their own ancillary services rates. Kentucky Power's PJM ancillary services rates are not the Companies' filed rates, and they should not be treated as if they were.

[16] At the beginning of his supplemental testimony Mr. Rábago says that he will address ancillary services cost but he never does. Case Nos. 2020-00349 and 202-00350, Supplemental Testimony Karl R. Rábago, at p. 1.

Q. How should ancillary services costs be calculated?

A. As I explained in my supplemental testimony, it is my conclusion that the avoided ancillary service costs are zero. *Schedule 1: Scheduling, System Control and Dispatch* relates to fixed dispatch center costs that simply cannot be avoided by increased or decreased generation on the system. *Schedule 4: Energy Imbalance Service* is an ancillary service charge that applies only to differences that occur between the scheduled and actual delivery of energy by a customer transmitting power across the Companies' transmission system. Therefore, costs recovered under Schedule 4 cannot possibly be avoided by energy supplied to the grid by customer-generators. Similarly, *Schedule 9: Generator Imbalance Service* applies only to differences that occur between the output of a generator located in the Transmission Owner's Balancing Authority and a delivery schedule provided by the generator. Therefore, costs recovered under Schedule 9 cannot possibly be avoided by energy supplied to the grid by customer-generations.

Schedule 2: Reactive Supply and Voltage Control recovers costs of specific components of a generator that can provide reactive power (VAR). Therefore, to the extent that the cost of a generator is avoided, whether it is a conventional generator or otherwise, the avoided cost of the components that could supply VARs would also be avoided. Therefore, an additional avoided cost for reactive power should not be added beyond what is recovered through an avoided generation capacity component. In other words, the avoided cost of reactive power is embedded in the avoided generation capacity cost.

An argument can be made that the costs related to *Schedule 3: Regulation and Frequency Response*, *Schedule 5: Spinning Reserve Service*; and *Schedule 6: Operating Reserve Service* could be avoided if generation capacity costs are deemed to be avoidable. In the Companies' Open Access Transmission Tariff ("OATT") approved by FERC, these three ancillary service rates are calculated as a specified percentage of the Companies' fixed generation capacity costs. Because it is the Companies' conclusion that customer-generators providing excess energy under NMS-2 do not avoid any generation capacity cost, it is also the Companies conclusion that the avoided cost related to these three ancillary services is also zero. However, if the Commission concludes that an avoided generation capacity cost is appropriate, the percentages embedded in these three ancillary service rates should be applied to the avoided generation capacity cost to determine the avoided ancillary services costs. The percentage applied the fixed generation costs in *Schedule 3: Regulation and Frequency Response* is 1%; the percentage applied the fixed generation costs in *Schedule 5: Spinning Reserve Service* is 1.5%, and the percentage applied the fixed generation costs in *Schedule 6: Operating Reserve Service* is also 1.5%.

VI. AVOIDED TRANSMISSION CAPACITY COST

Q. What do witnesses Rábago and Barnes recommend for an avoided transmission capacity component?

A. Again, Mr. Rábago does not calculate an avoided transmission cost component, nor does he suggest a methodology for determining avoided transmission costs. While

Mr. Barnes does calculate transmission costs for KU and LG&E, he derives the values from the Companies' embedded cost of service studies.

Q. Does the Companies' embedded cost of service study reflect *avoided costs*?

A. Clearly not. Embedded costs have no relationship to the Companies' avoided costs. Embedded costs cannot be used as a proxy for avoided costs. 807 KAR 5:054 Sec. 1(1) 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." The embedded cost of service study measures the Companies ***total*** fixed and variable costs incurred to provide service to customer and not the ***incremental*** costs which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source.

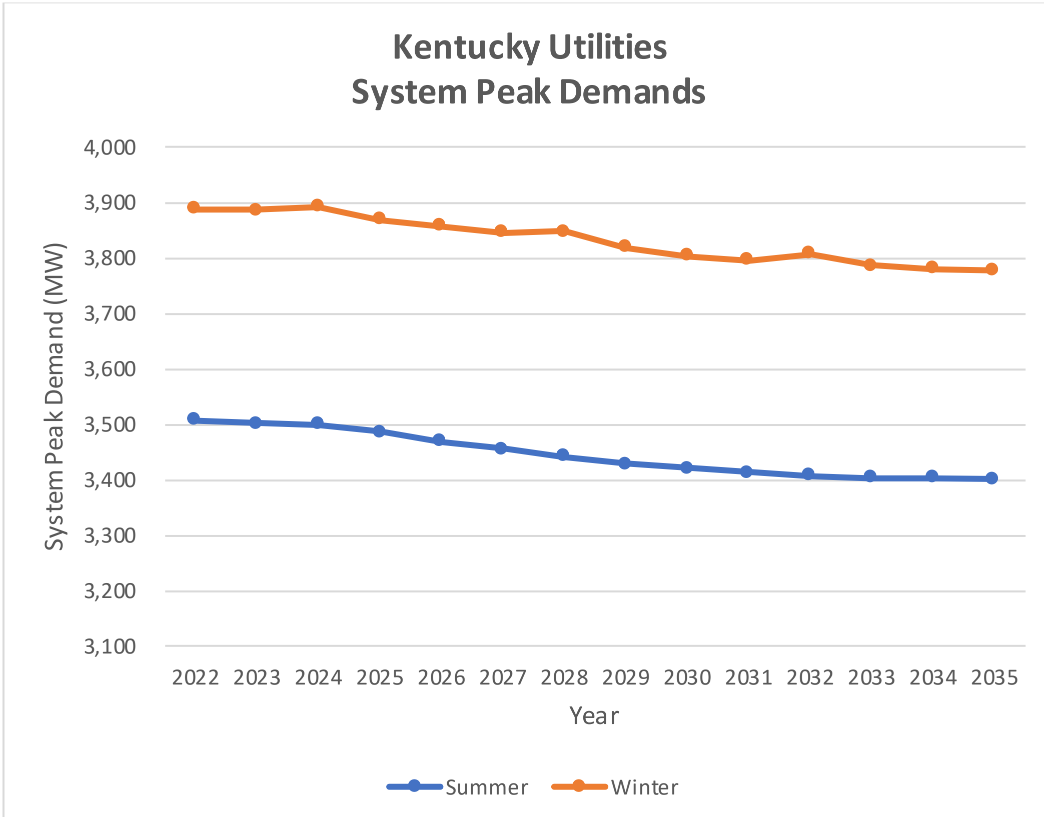
Q. What is wrong with using embedded cost value as a substitute for avoided cost?

A. Besides the fact that embedded costs and avoided costs are like apples and oranges, on a transmission system with generally adequate capacity and for which peak demands are projected to remain flat or to decline somewhat over the next decade or more, relying on an embedded cost would *grossly* overstate the costs that could possibly be avoided by the Companies. Embedded fixed cost measures the cost of ***all*** of the utility's plant that has been installed to date, and reflects the cost of serving ***total demand***, not incremental demand. Avoided cost represents the utility's marginal or incremental cost. In the context of energy supplied by customer generators, avoided capacity costs represent the utility's current or future costs than can be avoided by purchasing the energy from customer-generators. For systems with little growth or declining demands, such as KU and LG&E, any such avoided cost will be very low or zero. This is because such systems will generally have sufficient or excess capacity to serve their demands. Reductions in system demands created by customer-generators would not result in material reductions in future plant costs because with systems that have flat or declining demands, there is little or no marginal plant to avoid. This demonstrates what is wrong with using embedded cost as a proxy for avoided cost, as proposed by Mr. Barnes, particularly for systems such as KU and LG&E that have flat or declining demands. This is another instance where Mr. Barnes ignores a proper analysis of the Companies' avoided costs in favor of an approach that results in an overstated value.

Q. Please explain further how the system peak profile on KU's system indicates that there would be little or no avoided transmission costs resulting from the energy supplied to the grid by customer-generators.

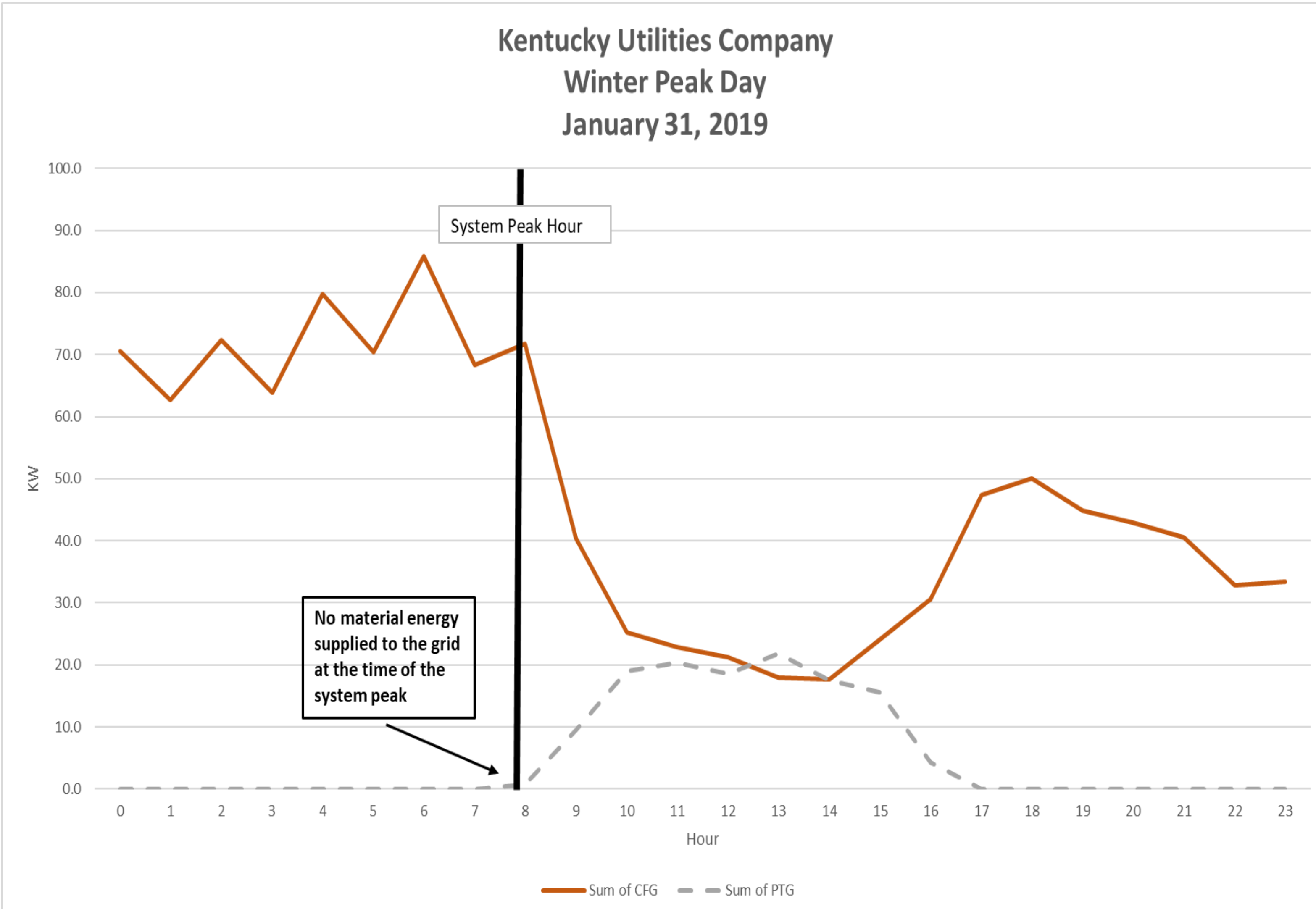
A. KU is a winter peaking utility. Therefore, its transmission system is largely designed to meet winter peak demands. The following graph (GRAPH 5) shows projected Summer and Winter peak demands for KU for the years 2022 through 2035 from the Companies' 2021 Business Plan:

GRAPH 5



As can be seen from this graph, KU's system peak occurs during the winter. These winter peak demands occur either in morning hours (around 6:00 AM) or evening hours (around 9:00 PM). The graph shows declining winter and summer system peak demands for KU. GRAPH 6, which can be found on a subsequent page below, shows the energy supplied to the grid from customer-generators on KU's winter peak day that occurred on January 31, 2019. As can been see from this graph, customer-generators were supplying essentially zero energy to the grid at the time of this peak. Therefore, it is not reasonable that customer-generators providing excess energy under NMS-2 could possibly avoid material transmission costs on KU's system. KU's summer peak demands are significantly less than its winter peak demands, and both the winter and summer peaks are decreasing over the planning period. The transmission facilities that have been installed by KU to serve its much higher winter peak demand demands would generally be adequate to serve its summer peak demands. But even on any parts of the transmission system which might possibly be designed for summer demands, because of the KUs declining summer demands, there would still be sufficient capacity to serve future demands. Therefore, the energy supplied by customer-generators could not avoid a material amount of costs related to facilities sized to meet summer demands. Therefore, it simply is not plausible that customer-generators could avoid material costs on KU's transmission system, as suggested by Mr. Barnes. Including any value for avoided transmission costs in the compensation rate for energy supplied by customer-generators under KU's NMS-2 schedule – but especially the grossly overstated amount based on embedded costs recommended by Mr. Barnes – would represent a subsidy to NMS-2 customer-generators. Mr. Barnes's recommendation, which is based on full embedded cost and not avoided cost, would grossly overcompensate customer-generators for the energy they supply to the grid. Mr. Barnes simply ignores the fact that KU is a winter peaking utility and that its transmission system is designed to meet winter system demands. He also ignores the fact that KU's peak demands are decreasing. His assumption that energy supplied from customer-generators could avoid a value equal to *full embedded costs* on a winter peaking system is indefensible.

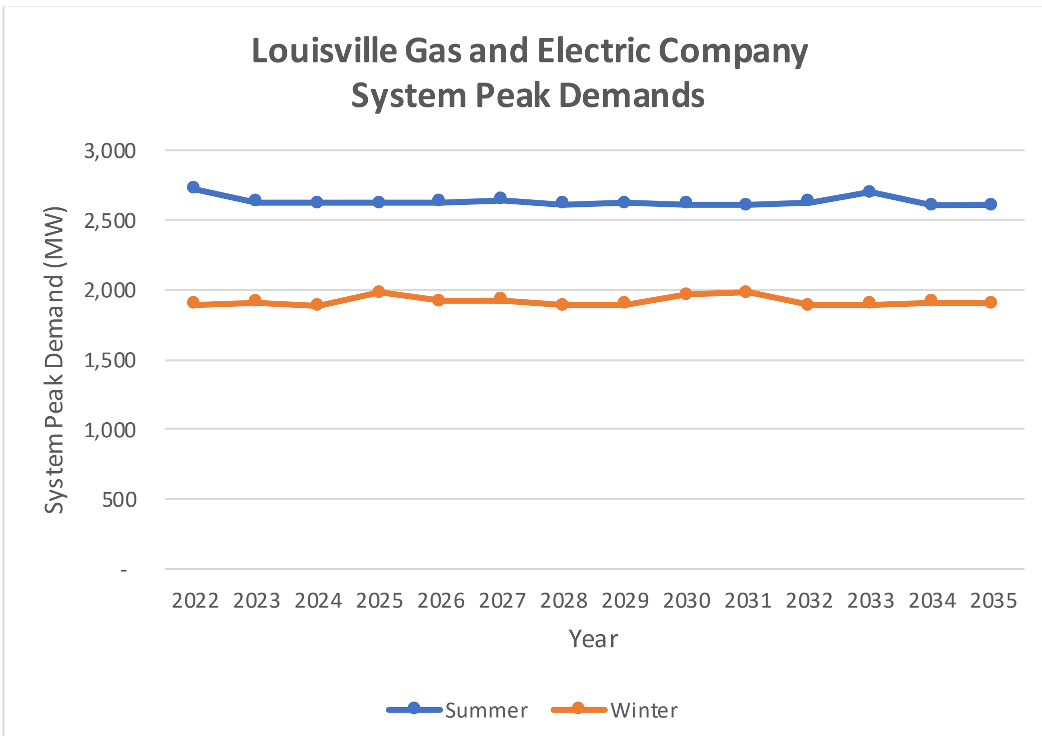
GRAPH 6


Kentucky Utilities Company
Winter Peak Day
January 31, 2019
System Peak Hour
No material energy supplied to the grid at the time of the system peak
KW
Hour
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Sum of CFG
Sum of PTG

Q. What does the system peak profile for LG&E inform us about LG&E's avoided transmission costs?

A. LG&E is a summer peaking utility. The following graph (GRAPH 7) shows projected Summer and Winter peak demands for LG&E for the years 2022 through 2035 from the Companies' 2021 Business Plan:

GRAPH 7



For LG&E, its summer peak demands are projected to remain flat over the next decade or more, with a slight downward trend in LG&E's summer peak demands. This means that LG&E's current transmission capacity should generally be adequate to serve future load on the system. This is confirmed by the modest capacity-related plant that

LG&E plans to install over the next decade, as discussed in my supplemental testimony in these proceedings.

Q. Can a stronger case be made for a small avoided transmission cost component for LG&E than for KU?

A. Not really. It is my conclusion that energy supplied to the grid by NMS-2 customers will not in reality avoid any transmission costs on either system. The energy supplied from solar facilities is intermittent, and thus cannot be relied on to provide firm capacity. Furthermore, the amount of energy supplied by customer-generators under net metering tariffs is tiny compared to the Companies' total energy requirements. The 1% cap set forth in KRS 278.466(1) means that energy supplied by net metering customers will remain small.

Because NMS-2 allows customer-generators to connect anywhere on KU's and LG&E's systems, and are indeed spread out across those systems, there is no certainty that these customer-generators will be concentrated in the limited areas of the transmission systems where some small amount of load growth is being seen. For any transmission facilities planned to be installed at a particular location to be avoided, basically all of the net metering served by the Companies would have to be concentrated in those areas, which does not reflect the current reality that net metering customers are spread throughout the service territory nor does it reflect the 15% limitation on the aggregated net metering generations on any radial distribution circuit's peak load currently set forth in the Companies' tariffs.

For all these reasons, it is unrealistic that energy supplied by customer-generators could avoid any transmission capacity costs. But this is even more the case for KU than for LG&E. Because KU is a winter peaking system, it is even less likely that energy supplied by customer-generators could avoid any transmission costs. In his supplemental testimony, Mr. Barnes has not delved into any of these considerations. He seems intent on simply attributing a high value for a transmission cost component without analyzing the Companies' avoided transmission costs.

Q. Therefore, what is your recommendation regarding avoided transmission costs?

A. I continue to recommend that the avoided transmission cost component for NMS-2 should be zero. At a maximum, the avoided transmission cost component should be $0.00025/kWh for KU and $0.00010/kWh for LG&E, as calculated in my Supplemental Testimony, Supplemental Exhibit WSS-1.

VII. AVOIDED DISTRIBUTION CAPACITY COST

Q. What do witnesses Rábago and Barnes recommend for an avoided distribution capacity component?

A. Again, Mr. Rábago does not calculate an avoided distribution cost component, nor does he suggest a methodology for calculating avoided distribution costs. Likewise, Mr. Barnes does not perform an analysis to calculate an avoided distribution cost component. But he states that "conceptual level, the unit cost-based methodology (grossed up for demand losses) that I identify for transmission costs can also be used for distribution costs."[17] So, what Mr. Barnes is recommending is to use the Companies' embedded costs to calculate avoided distribution costs. Again, embedded costs have no relationship to the Companies' avoided costs. Embedded costs cannot be used as a proxy for avoided costs. The Companies' embedded cost of services studies filed in these proceedings are not marginal or avoided cost studies. As I discussed in the context of transmission costs, embedded costs will be much higher than avoided costs for utilities such as KU and LG&E that have flat or declining loads. The Companies are spending very little to accommodate growth on their systems. What this means is that compensating customer-generators for distribution capacity costs that they will not and cannot avoid will serve only to increase the Companies' rates for all customers. For KU, which has a high concentration of space heating load, it would be nearly impossible for energy supplied from customer-generators to avoid any distribution facilities.

Q. Therefore, what is your recommendation regarding avoided distribution costs?

A. I continue to recommend that the avoided distribution component for NMS-2 should be zero. At a maximum, the avoided distribution cost component should be \$0.00046/kWh for KU and \$0.00012/kWh for LG&E, as calculated in my Supplemental Testimony, Supplemental Exhibit WSS-2.

[17] *Op. cit.,* at p. 11.

VIII. AVOIDED CARBON AND ENVIRONMENTAL COMPLIANCE COSTS

Q. What do witnesses Rábago and Barnes recommend for an avoided carbon and environmental compliance costs component?

A. Again, Mr. Rábago does not calculate an avoided carbon and environmental compliance costs cost component, nor does he suggest a methodology for this component. Likewise, Mr. Barnes does not perform an analysis to calculate an avoided carbon and environmental compliance costs cost component. Ultimately, Mr. Barnes states that the "avoided environmental compliance cost rate is difficult to quantify without a detailed analysis that projects forward the environmental compliance costs for the Companies by year and separates them out into residential and non-residential segments."[18] Unlike his recommendation for transmission and distribution costs, Mr. Barnes has this time reverted to an analysis of future costs. But even in his high-level description of a possible methodology, he failed to state that only *avoidable* environmental compliance costs should be included in any such calculation. The only likely reasons that the Companies' existing generating facilities will be retired earlier than when they are currently planned are because of new environment laws that force the retirement of the facilities or if it is no longer economical to operate the units. Mr. Barnes fails to explain how environmental costs related to the Companies' existing generating units would be avoided by energy supplied to the grid by customer-generators. In fact, it is abundantly obvious that they

[18] *Op. Cit.*, at p. 12.

cannot be, as Mr. Sinclair addresses in his supplemental rebuttal testimony.

IX. JOB BENEFITS

Q. What do witnesses Rábago and Barnes recommend for an avoided distribution capacity component?

A. Again, Mr. Rábago does not calculate jobs benefit component, nor does he suggest a methodology for calculating one. Likewise, Mr. Barnes does not calculate a jobs benefit credit nor does he offer a methodology for calculating such a credit. He ultimately suggests that that the Commission "consider Job Benefits as a qualitative factor."

Q. What is your recommendation regarding a Jobs Benefit Credit?

A. As I explained earlier, I do not believe that a Jobs Benefit Credit should be included in the compensation rate for NMS-2. It is an externality that should not be considered in setting rates. As it has succinctly stated in other orders, "the Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service."[19] This determination by the Commission can be reasonably be expanded to conclude that the Commission has no jurisdiction over jobs.

X. CONCLUSION

Q. Do you have any concluding comments?

A. Yes. Witnesses Rábago and Barnes are proposing frameworks, methodologies, and

[19] Commission Order in Case No. 2017-00441, dated October 5, 2018, at p. 28. *Op. Cit.*

rate components that will provide what is essentially a windfall to customers who can afford to install solar panels and provide excess energy under NMS-2 at the expense of all other customers. While Mr. Rábago provides no numerical values and no methodologies for calculating avoided costs, he recommends including additional externalities in the compensation rate that would be paid to NMS-2 customers. By mixing a combination of varying and mutually opposed cost-of-service methodologies and filed rates from PJM, Mr. Barnes deploys what can only be described as ratemaking alchemy to develop a compensation rate for NMS-2. To obtain a compensation rate favorable to his client's interests, Mr. Barnes mixes filed generation capacity and ancillary services rates that have been approved by FERC for PJM *with* energy prices at a PJM interface that has no bearing on the Companies' avoided costs *along with* embedded transmission and distribution costs that also bear no relationship to the Companies' avoided costs. Of course, the windfall to NMS-2 proposed by Rábago and Barnes would be paid by the Companies' other residential customers, many of whom are low income customers. It is my recommendation that the Commission approve the recommended cost components that I provided in my Supplemental Testimony.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF BUNCOMBE)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 4th day of August 2021.

Jasmine Myers
Notary Public
Transylvania County, NC
My Commission Expires: 03/07/2

_______________________(SEAL)
Notary Public

Notary Public ID No. 202106900003

My Commission Expires:

3/7/2026

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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**

In the Matter of:

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**

SUPPLEMENTAL REBUTTAL TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: August 5, 2021

Table of Contents

Section 1 – Introduction and Overview

Q. Please state your name, position, and business address.

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut assertions made by Messrs. Barnes, Owen, and Rábago in their supplemental testimonies regarding:

1. The appropriate method for calculating the Companies' avoided energy costs,
2. The appropriate method for calculating the Companies' avoided generation capacity costs, and
3. The appropriate method for addressing unknown and unknowable future CO_2-related costs.

Also, my testimony will explain how the Commission's requirement that utilities like KU and LG&E provide reliable service at the lowest reasonable cost allows them to directly determine their own avoided costs rather than relying on proxy data based on PJM tariffs as recommended by Mr. Barnes. Furthermore, because the Companies operate as standalone utilities rather than as members of PJM, certain concepts like generation-based ancillary service and environmental costs are directly reflected in avoided energy and generation capacity costs and do not require separate "adders." Finally, I demonstrate that the Current Market Price method for determining avoided energy and generation capacity prices used in the NMS-2, SQF, and LQF riders that I recommended in my Supplemental Direct Testimony results in the lowest reasonable costs for customers and reflects actual options available to the Companies for reliably meeting our customers' energy needs.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my supplemental rebuttal testimony, as well as supporting workpapers being filed with my testimony:

Supplemental Rebuttal Exhibit DSS-1	Levelized Cost of Residential and Utility-Scale Solar
Supplemental Rebuttal Exhibit DSS-2	Typical 15-minute Residential Load and Solar Generation
Supplemental Rebuttal Exhibit DSS-3	2018 IRP Reserve Margin Analysis

Section 2 – Distributed Solar Technology and Economics

Q. To respond to the supplemental testimonies filed by Messrs. Barnes, Owen, and Rábago, please provide some context concerning the economics of distributed solar technology. To begin, what is distributed solar technology?

A. Distributed solar technology generally involves putting solar panels on the roof of a home or business. The electricity generation process of converting light into electricity is no different on a roof than it is in an open field. Thus, rooftops and open fields are just different places to site a generation facility.

Q. Does siting a solar power plant on a residential roof potentially impact the performance of the solar panels as compared to siting the power plant in a field?

A. Yes. First, rooftops do not necessarily face the optimal direction or have the optimal slope to efficiently capture the sun's energy. In an open field, it is much easier to optimally align the panels for energy production. Second, siting a solar power plant on a roof seems to limit the ability to use more modern solar technology like bi-facial and sun tracking panels. Finally, some rooftop power plants are more at risk of shading from nearby trees and buildings than would be the case for a solar plant sited in a field. The combination of these three factors results in the typical rooftop solar power plant having an annual capacity factor of around 16.6 percent compared to a solar plant sited in a field with the latest technology producing at around a 27.9 percent annual capacity factor.[1]

Q. How does the capacity factor difference impact the economics of solar?

A. It has a big impact because almost all of the cost of a solar power plant is the upfront capital cost of installing the panels. Thus, if the plant generates less energy, its cost per unit of energy (e.g., MWh) will be higher. For example, according to National Renewable Energy Laboratory ("NREL"), the cost of a typical rooftop solar power plant is around $2,340/kW.[2] Converting this cost to an annual cost and then dividing it by annual energy assuming the lower residential 16.6 percent capacity factor results in a cost of around $0.09/kWh ($90/MWh). Using this same annual cost and dividing it by the higher capacity factor that is possible by siting the plant in a field and using better technology reduces the cost to $0.054/kWh ($54/MWh).[3]

Q. Is the cost per kW of siting a solar power plant in a field the same as siting it on a roof?

A. No. According to NREL, a solar plant in a field, using bi-facial panels and single axis tracking would cost around $1,224/kW or almost 50 percent less than siting it on a

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[1] *See* Supplemental Rebuttal Exhibit DSS-1. Note that for purposes of this testimony, the terms "rooftop solar" and "residential solar" are used interchangeably. Also, all solar power plants located in a field are assumed to be "utility-scale" per NREL's description.
[2] *See* Companies' Response to PSC 6-7.
[3] *Id.*

rooftop. This lower cost per kW is largely due to economies of scale. Using the same method as above, the cost of the field-sited solar plant falls to around $0.03/kWh ($30/MWh). Thus, while the typical rooftop sited solar plant costs around $0.09/kWh ($90/MWh), the same sunlight can be converted to electricity in a field for one-third the cost.

Q. Given that siting a solar power plant on a roof is much more expensive, please describe the economics of installing solar panels from a homeowner's perspective.

A. Any commercially successful product or service typically performs a task better or cheaper or both than existing or alternative products or services. In the case of residential solar, the solar installation company is primarily trying to convince the homeowner that they can reduce their overall electricity cost by siting a power plant on their roof. However, this usually does <u>not</u> involve the homeowner disconnecting from the grid and relying solely on their own power plant. Thus, rooftop solar does not replace service from the electric grid; rather, it requires it. In a sense, a homeowner that installs rooftop solar is buying a product that complements their grid service rather than substituting for it.

The economics of rooftop solar to the homeowner depends on three factors:

- their electricity usage pattern and its relationship to solar irradiance,
- the energy rate <u>charged</u> by the utility to the homeowner (potential savings to the homeowner), and
- the energy rate <u>paid</u> by the utility for any excess energy the solar plant pushes onto the grid (potential revenue to the homeowner).

Note that the first two items involve only the homeowner while the third item involves their neighbors. Thus, when a homeowner signs a contract with a solar installer, they are also indirectly committing their neighbors to the project without their consent.

Q. How is a homeowner's decision to install solar panels any different from their decision to install a technology that reduces their energy consumption?

A. When a homeowner decides to install a more efficient air conditioner, or more insulation, or an LED lightbulb, they pay the full cost of the product and receive the full benefits. The risk of whether or not their investment in energy efficiency pays off for them is entirely theirs. However, when a homeowner decides to install a solar power plant on their roof, their economics depends, in part, on their neighbors' willingness to pay for part of the project. It is the neighbors' involuntary participation in putting a solar plant on a roof that necessitates discussions around avoided energy and capacity costs.

Q. Please explain why rooftop solar requires the electric grid to function economically.

A. In order to operate properly, electric equipment requires a power source that provides electricity within tight parameters (e.g., voltage and frequency). Also, the demand for electricity must be met instantaneously, so generation sources must constantly ramp up and down to meet changes in demand. Figures 1a and 2a in Supplemental Rebuttal Exhibit DSS-2 show the 15-minute load for a KU all-electric customer for a week in January and July.

Meeting this fluctuation in a customer's demand is part of the normal operations of the grid. However, the energy output of a solar power plant, regardless of where it is sited, fluctuates according to the time of the year and cloud conditions. Figures 1b and 2b in Supplemental Rebuttal Exhibit DSS-2 show the expected energy output of a typical rooftop solar installation for the exact same time as the customer load shown in Figures 1a and 2a. As can be seen from this exhibit, the two seldom line up. In fact, the correlation coefficient between load and generation for this particular customer is just -0.003 in the summer and -0.09 in the winter. The correlations are not materially different (i.e., -0.09 in the summer and -0.14 in the winter) considering only the hours with solar production. This lack of correlation illustrates why the grid is required to instantaneously either provide or absorb the difference in energy demand and production.

Q. Could a homeowner install a battery to handle this difference and disconnect from the grid?

A. Yes, but this would require significantly more investment, space for the batteries, and probably more roof space for solar than is typically available for most homeowners. This is likely why one does not observe this behavior very often, not just in Kentucky but nationwide.

To illustrate the challenges of going it alone with solar and batteries, the Companies used real load and solar irradiance data to determine the volume of solar and storage capacity that would be required to serve the LG&E Highland 1103 circuit.[4] Even assuming every home in this highly residential circuit installed rooftop solar and in-home battery storage, it was still necessary to use 246 acres of land for solar panels

[4] See attachment to Companies' Response to PSC 7-21(b). The Companies' LG&E Highland 1103 circuit analysis is also available at: https://lge-ku.com/sites/default/files/Using-Solar-And-Storage-Case-Study-LGE-Highland-1103-Circuit.pdf.

and energy storage. This area was basically the same as the land area of the distribution circuit itself. Thus, if an entire circuit of customers cannot site solar panels on their roofs and batteries in their homes to serve their load, it is highly unlikely that most typical homeowners would be able to do so.

Q. Do others contend the grid can be viewed as acting as a battery for the homeowner?

A. Yes. In fact, some in the solar industry make that argument. For example, in a recent television interview, Steve Ricketts, the General Manager and Owner of Solar Energy Solutions said, "When the home is not using the energy the solar roof is taking in it goes straight to the utility company where it's stored for later use. Right now, it's probably pushing back to LG&E. Tonight, when the owner comes home, they'll pull that energy back."[5] Mr. Ricketts in not alone in this characterization: for example, EnergySage, a popular site that advocates for solar generation,[6] states, "In essence, net metering is like having the grid serve as a giant solar battery."[7]

Q. Do the Companies offer a solar energy storage or battery rider?

A. No, but it is certainly possible to develop one. Such a rider would have to recognize the use of the distribution and transmission grid to move the energy from the home to the battery storage site (e.g., the Companies' 1 MW, 2 MWh battery at the E. W. Brown station), a portion of the costs of the battery itself, and the energy losses for the round

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[5] "Kentucky's First Tesla Solar Roof," WHAS 11, May 21, 2021.

[6] According to EnergySage, "Millions of people use EnergySage each year to research and shop for solar through our network of pre-screened, local installers." https://www.energysage.com/ (accessed May 6, 2021; archived at https://web.archive.org/web/20210506132812/https://www.energysage.com/).

[7] EnergySage, "Net metering for home solar panels" (updated 2/11/2021), available at https://www.energysage.com/solar/101/net-metering-for-home-solar-panels/ (accessed May 6, 2021; archived at https://web.archive.org/web/20210506132151/https://www.energysage.com/solar/101/net-metering-for-home-solar-panels/). *See also* Companies' Response to KSIA PHDR 5.

trip including battery losses. For example, it is likely that for every kWh sent to the battery, only 0.77 kWh would be returned because of losses. This type of storage service would be very much akin to what gas pipelines offer for natural gas storage that the Companies purchase to ensure reliable fuel supply necessary to operate their gas turbines.

Q. Is Mr. Barnes's recommendation of a monthly netting period akin to the battery storage concept?

A. Absolutely. As Mr. Barnes states, "Real-time export rates can make predicting customer savings close to impossible."[8] In other words, he acknowledges that homeowners putting solar panels on their roofs require the use of the grid to balance their load and generation. However, Mr. Barnes's recommended solution is to let customer-generators use the grid for free to financially store their electrons rather than pay for the service they need and desire.

Q. How would charging a customer for solar energy storage impact the economics of installing rooftop solar?

A. It would remove a homeowner's neighbors from the economics of their decision by eliminating the issues associated with energy pushed back onto the grid. From an economics perspective, a solar energy storage rider would internalize the cost of a homeowner's decision to install solar panels as opposed to creating an externality in the form of energy put on the grid that must be addressed by their neighbors.

[8] Barnes Supplemental Testimony at 14.

Section 3 – NMS-2 Rate

Q. Please describe your knowledge of the Companies as it relates to distributed solar generation technology.

A. I have had responsibility for the Companies' generation planning since 2007 and sales forecasting since around 2001. The Corporate Fuels and By-products department and the Power Supply department are under my supervision and direction as Vice President, Energy Supply and Analysis. In these capacities, it is my responsibility to ensure that the Companies have the generating resources to reliably serve load at the lowest reasonable cost. This includes the impacts both load and generating resources of a homeowner's decision to put solar panels on their roof.

Q. Do your business groups have any procurement responsibility?

A. Yes. The Corporate Fuels and By-products department and the Power Supply department are involved in procuring:

- approximately $800 million annually of coal, natural gas, oil, and associated barge, rail, pipeline, and truck transportation necessary to deliver fuel to the generation stations;
- pollution control reagents and transportation such as limestone for FGD operations and ammonia for SCR operations; and
- wholesale power via long-term contracts like the Bluegrass Unit 3 gas tolling agreement (expired in April 2019) and the recent Rhudes Creek Solar power purchase agreement ("PPA"), as well as via the hourly wholesale market.

Finally, the vice president of Project Engineering has reported to me since 2017, and his team procures construction services involving hundreds of millions of dollars for projects associated with pollution control equipment, coal combustion residual management, and new generation.

Q. Are there any guiding principles that govern your groups' procurement practices?

A. There are several, but the two that merit the most emphasis are reliability and low-cost for our approximately one million customers. The Companies take seriously their responsibility "to provide the lowest possible cost to the rate payer."[9] The Commission's May 8, 2020 order in Case No. 2020-00016 involving the Rhudes Creek Solar PPA further discussed our low-cost responsibility:

> Electric utilities' generation and energy decisions play a fundamental role in ensuring service is provided to customers at the "lowest possible cost." As part of an electric utility's planning to ensure compliance with that requirement, they must ensure their actions do not lead to wasteful duplication, or procuring resources or assets in "excess of capacity over need."[10]

My recommendations for setting avoided energy and capacity prices for the Companies' NMS-2, SQF, and LQF riders are in compliance with this statement from the Commission. The recommendations by Messrs. Barnes, Owen, and Rábago are not.

Q. Do you believe that the energy a customer-generator puts back on the grid should be subject to the same lowest-reasonable-cost procurement principles?

A. Yes. The Companies are acting on behalf of their one million customers and from a generation resource perspective, a kWh from a solar panel on a roof provides the same

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[9] *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source under Green Tariff Option #3,* Case No. 2020-00016, Order at 7 (PSC Ky. Dec. 16, 2020), *quoting Public Service Comm'n v. Dewitt Water District,* 720 S.W.2d 725, 730 (Ky. 1986) ("The Commission has ignored one of its most important roles, which is to provide the lowest possible cost to the rate payer.").

[10] Case No. 2020-00016, Order at 7 (Ky. PSC May 8, 2020).

service as a solar panel in a field or from an existing generator (after adjusting for line losses, if any, as Mr. Seelye discusses). As stated in my Supplemental Direct Testimony, our one million customers should pay no more for energy and capacity from an NMS-2 customer-generator than they would from any other generation source. As the Commission noted in its June 18, 2020 order in Case No. 2020-00016, "The economics of providing renewable electricity to accommodate specific customer preferences will be what they are, but the costs must be borne by participants themselves."[11] There is no reason why the NMS-2 compensation rate for energy pushed back on the grid should depart from the same reliability and low-cost principles that are applied to all of the Companies' procurement activities.

Q. Based on these established principles, what is your view of Mr. Barnes's recommendations regarding avoided costs for energy, capacity, CO_2, and environmental compliance?

A. At a high level, Mr. Barnes's approach to calculating avoided costs for these components focuses not on the Companies' future costs but rather relies almost exclusively on the costs of others (e.g. PJM) and is, in the case of avoided energy costs, backward looking.

The Companies, however, cannot avoid in the future the past energy prices of an RTO that they are not in.

Furthermore, his methodology seems designed to produce the highest possible price for energy NMS-2 customers produce to the grid, . This advances the interest of his client, the Kentucky Solar Industries Association, some (perhaps all) of whose

[11] Case No. 2020-00016, Order at 14-15 (Ky. PSC June 18, 2020).

members have a direct financial interest in selling rooftop solar panels to homeowners. not the lowest reasonable cost for all customers.

Q. Are there reasons why applying PJM costs is not appropriate to the Companies' situation?

A. Yes. The RTO uses complicated tariffs and various price signals in the hope that the resulting generation fleet will prove to be reliable and low-cost. On the other hand, the Companies operate as a standalone, vertically integrated utility with an explicit obligation to serve customer load at the lowest reasonable cost. Thus, KU and LG&E's generation decisions are made to purposefully assemble, maintain, and operate a generation fleet to accomplish this task. In contrast, the challenge facing an RTO is described by Tony Clark (former FERC commissioner) and Vincent Duane (former senior vice president with PJM):

> The reality for RTOs is that price arises from an immense set of rules that establish an auction and define market clearing algorithms run by complex market settlement software programs to produce a single-clearing price paid to all supply and charged to largely passive demand. In short, the exercise of RTO price formation combines abstract art with impenetrable science.[12]

The Companies face no such challenge. Actual prices for technologies and suppliers obtained from competitive bid RFPs are used to determine the least-cost generation portfolio. The generation fleet is dispatched based on least-cost principles. Our customers pay just the cost for their energy – not a locational marginal price that is unrelated to the actual cost of running the generation units used to serve their load. Finally, the Companies' decisions to procure capacity are subject to review by the

[12] Clark, Tony and Vincent Duane, "Stretched to the Breaking Point: RTOs and the Clean Energy Transition," page 2, July 2021, *available at* https://www.wbklaw.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf.

Commission and must be presented in a transparent, understandable format; they are not the result of an "impenetrable" algorithm or complicated auction process.

Q. How do the Companies' avoided energy costs compare to those recommended by Mr. Barnes?

A. As I described in my Supplemental Direct Testimony, I recommend using the avoided energy costs from the Companies' 2021 Business Plan ("2021 BP") that are calculated using forecasts of the Companies' own generating plants and fuel costs (a significant portion which is already locked-in via long-term contracts and forward purchases) weighted by the energy generating profile of various technologies. The table below shows by year the difference between the Companies' projected avoided energy costs and PJM's historical market prices recommended by Mr. Barnes. Because PJM sets its market prices based on the highest accepted offer price from a generator, it is not surprising that the average PJM prices from 2017 to 2019 are 43% higher than the Companies' cost-based projected avoided energy costs for 2022 to 2024 ($32.54/MWh vs. $22.82/MWh).

	PJM South Import LMP (9 AM-6 PM; $/MWh)				2021 BP Avoided Energy Costs (9 AM-6 PM; $/MWh)			
Month	**2017**	**2018**	**2019**	**Average**	**2022**	**2023**	**2024**	**Average**
1	29.51	49.13	27.01	35.22	22.50	22.47	22.82	22.60
2	24.34	25.97	25.31	25.21	22.38	22.31	22.72	22.47
3	31.17	26.98	26.03	28.06	22.49	22.40	23.09	22.66
4	31.00	35.41	26.90	31.10	22.70	22.92	22.80	22.81
5	34.99	46.46	28.35	36.60	22.34	22.55	22.70	22.53
6	32.02	38.52	29.04	33.19	23.40	23.05	23.24	23.23
7	38.98	35.84	35.08	36.63	23.43	23.40	23.42	23.42
8	31.15	38.81	30.03	33.33	24.13	23.47	23.62	23.74
9	41.00	42.43	41.14	41.52	22.87	22.89	23.10	22.95
10	30.09	37.90	33.86	33.95	23.03	22.66	22.77	22.82
11	25.82	36.32	25.73	29.29	22.46	22.32	22.19	22.32
12	25.43	30.76	22.89	26.36	22.27	22.27	22.51	22.35
Average	31.29	37.04	29.28	32.54	22.83	22.73	22.91	22.82

Q. Does your group engage in wholesale market transactions at the PJM South Import node?

A. Yes. The Power Supply group reports to me and is responsible for optimizing the Companies' generation in real time by buying and selling energy with neighboring RTOs and utilities. PJM South Import is where we make a significant amount of our off-system sales because it is often higher priced than MISO or TVA. As the table below shows, from 2017 through 2019, the Companies sold 576,458 MWh at an average price of $57.27/MWh at PJM South Import. Per previous Commission orders, 75 percent of the margin from these off-system sales was returned to customers. The table also shows that on rare occasions the Companies were able to purchase energy from PJM South Import to displace higher cost generation. However, the Companies generally sell far more energy to others than purchased because of our low-cost generation fleet.

Year	Sales		Purchases		Total Volumes (MWh)	Purchases as % of Total Volumes
	MWh	$/MWh	MWh	$/MWh		
2017	148,007	38.99	975	18.41	148,982	1%
2018	335,439	70.59	0	0.00	335,439	0%
2019	93,012	38.33	5,502	16.66	98,514	6%
Total	576,458	57.27	6,477	16.92	582,935	1%

Our long experience in selling energy into PJM to benefit customers from the OSS tracker mechanism is another reason why the Commission should reject Mr. Barnes's recommendation to use PJM prices to represent the Companies' avoided energy cost. The evidence is clear that the Companies sell into PJM and seldom purchase energy from PJM.

Q. How does Mr. Barnes's view of avoided generation capacity costs compare to yours?

A. Mr. Barnes's avoided generation capacity method seeks to justify the highest possible avoided generation capacity costs. In fact, his recommended avoided generation capacity cost for rooftop solar of \$0.0357/kWh (\$35.70/MWh)[13]—just one of the seven avoided-cost categories in the Commission's Kentucky Power methodology—is more than the 20-year level price of \$0.02782/kWh (\$27.82/MWh) that the Companies agreed to pay Rhudes Creek Solar for <u>all</u> of the output of the solar facility, and the Companies receive the renewable energy certificates ("RECs") related to that output. Adding the average of 2017-2019 PJM prices from the table above (with no escalation) to his excessive avoided capacity value would mean customers should have been

[13] Note that the levelized fixed capital cost of a natural gas combined cycle unit (NGCC) including firm gas transportation would range from \$18.50/MWh (at an 80% capacity factor) to \$24.70/MWh (at a 60% capacity factor). There is no reason why the Companies would pay more for capacity from an intermittent solar facility than they would from a NGCC that is dispatchable around-the-clock.

willing to pay $0.06824/kWh ($68.24/MWh) for Rhudes Creek Solar energy. His claim that our one million customers should be willing to pay such an inflated price for solar energy strains credulity. As the economic analysis witness in the Rhudes Creek PPA case, there is no way I would have recommended proceeding with a solar PPA at Mr. Barnes' recommended price. In fact, the Companies received 75 responses from solar developers to the 2019 RFP that resulted in the Rhudes Creek PPA, and the *highest* response was $0.0554/kWh ($55.40/MWh). In short, there is no plausible rationale—certainly not one consistent with lowest reasonable cost principles—to support the avoided generation capacity cost recommended by Mr. Barnes.

As I stated in my Supplemental Direct Testimony, the Current Market Value method for calculating avoided capacity costs for fixed tilt (rooftop) solar technology is around $0.00190/kWh ($1.90/MWh) at the most, assuming that the NMS-2 rate should even include an avoided generation capacity component.

Q. How does Mr. Barnes compute avoided generation capacity cost in order to arrive at such an inflated value?

A. Mr. Barnes computes an avoided generation capacity cost as the product of an "effective solar capacity" and a capacity rate that is grossed up for secondary losses. Mr. Barnes computes an effective solar capacity by weighting a solar production profile according to hourly Loss of Load Probability ("LOLP")[14] where hourly LOLPs are translated to a percentage of total LOLP over the entire year. In doing this, each hourly percentage is multiplied by the forecasted hourly solar capacity factor (kWh/kW) and the result is summed to create the LOLP-weighted effective solar capacity. To compute

[14] LOLP is a measure of the probability that a system demand will exceed capacity during a given period.

the loss-adjusted capacity rate, Mr. Barnes divides the cost of capacity for an NGCC unit in $/kW by annual energy produced by a solar facility and then grosses the result up for 5% losses.[15]

Q. Do you agree with Mr. Barnes that the capital cost of a NGCC should be used as a proxy to help determine avoided generation capacity cost?

A. No. As explained in my Supplemental Direct Testimony and in Supplemental Exhibit DSS-2, in the absence of a market price, a simple cycle CT is often used as a proxy for capacity cost because it can be quickly started to meet reliability needs for any hour throughout the year. Mr. Barnes unnecessarily increases the proxy cost of capacity by using a NGCC because the extra capital cost per kW adds a heat recovery steam generator ("HRSG") and a steam turbine to the simple cycle CT configuration in order to capture the CT exhaust heat to reduce the overall heat rate of the facility. In other words, the added capital cost of the HRSG and steam turbine are there to reduce energy cost and expand capacity, not enhance the reliability of the simple cycle CT. Thus, the cost of the CT is more appropriate when evaluating pure capacity economics.

Q. While you disagree with the avoided generation capacity value recommended by Mr. Barnes, how does his methodology compare to the approach you have recommended?

A. Mr. Barnes's methodology is similar in concept to my Levelized Cost of a CT method, which estimates an avoided generation capacity cost based on the cost of a CT. However, Mr. Barnes' methodology significantly overstates the value of solar capacity in two ways. First, his methodology effectively ignores the Companies' need for

[15] See Supplemental Testimony of Justin R. Barnes at pages 8-9.

capacity in the winter and shoulder months. The LOLPs utilized by Mr. Barnes were computed for a year with normal or average weather. In a year with normal weather, the Companies' load is summer peaking and the percentage of annual LOLP in the winter and shoulder months (October through May) is close to zero (1%) while 99% of annual LOLP occurs in the summer months (June through September). However, in the Companies' service territory, annual peak demands can occur in the summer or winter months and the greatest risk for the highest demands (and the greatest consequence for loss-of-load events from customers' perspective) are in the winter months. Since 2010, the Companies' annual peak demand has exceeded 7,000 MW three times: once in the summer (August 2010) and twice in the winter (January 2014 and February 2015). In addition, because planned maintenance is assumed to have no impact on reliability due to our ability to schedule outages and still maintain adequate capacity, the Companies do not model planned maintenance when computing LOLP. Therefore, Mr. Barnes's methodology ignores the Companies' need for dispatchable capacity in the shoulder months when other units are offline for weeks at a time for maintenance, including nighttime hours. A reliability methodology that places a near-zero weight on the winter and shoulder months is clearly not prudent. Mr. Barnes's "effective solar capacity" is similar in concept to the annual availability factors I used to compute avoided capacity costs with the Levelized Cost of CT method.[16] However, unlike Mr. Barnes, I computed average annual availability factors by weighting all months equally because the system must be reliable in each and every month.

[16] See Table 8 on page 9 of Supplemental Exhibit DSS-2.

Second, Mr. Barnes's methodology effectively assumes that the Companies have an immediate need for additional generation capacity. This is clearly not correct. As discussed in Section 1 of Supplemental Exhibit DSS-2, the Companies evaluated two generating unit retirement scenarios and the earliest capacity need was 2028. After computing an avoided generation capacity cost, these costs must be aligned with the Companies' need for capacity when computing an avoided capacity price. Section 3 in Supplemental Exhibit DSS-2 explains how this should be done. Properly adjusting Mr. Barnes's inflated avoided generation cost to reflect the timing of the Companies' potential capacity need would reduce it to a less inflated value of $0.0198/kWh ($19.80/MWh) – a 44 percent reduction.

Q. You said that you have been responsible for the Companies' generation planning since 2007. Please explain, based on your experience, how the Companies use LOLP in generation planning.

A. The only uses of LOLP (also referred to as the likelihood of a loss of load event or LOLE) from a generation planning perspective is to aid in the identification of a target reserve margin and to assess the likelihood that the Companies' existing generation fleet can reliably serve load. This process is described in the reserve margin study that is filed with each IRP. Supplemental Rebuttal Exhibit DSS-3 contains the reserve margin study from the 2018 IRP. That study shows that to reduce the likelihood of a loss of load event to 1 event in 10 years the Companies would need a 25 percent summer reserve margin. The calculation of LOLP places no consideration on the cost of capacity and energy nor does it aid in determining the optimal economic generation fleet. It simply tells us whether or not the lights will stay on given a particular generation fleet. This contrasts with the economic reserve margin method that balances the cost of unserved energy with the cost of incremental capacity. As shown in Supplemental Rebuttal Exhibit DSS-3, the economic reserve margin in the summer is 17 percent. These two methods are the basis for the Companies' stated target reserve margin range of 17 percent to 25 percent.

All resource decisions (e.g., retirement of coal units, installing pollution control equipment, building Cane Run unit 7, entering into the Rhudes Creek Solar PPA) are based on the relative economics of actual alternatives – solicited via an RFP and developed in-house – that are evaluated based on their total capital and energy costs while maintaining system reliability consistent with the target reserve margin range. LOLP (or LOLE) is not used in any way to determine which resources or environmental compliance alternatives are the lowest reasonable cost.

Q. Do you have other concerns with Mr. Barnes's methodology?

A. Yes. First, Mr. Barnes's methodology ignores actual market price information for solar and wind resources. Whatever ability solar or wind resources have to avoid capacity and energy costs for customers is available directly through the market price of that resource and does not require the use of a proxy NGCC or any other technology (inside or outside of PJM). It is unreasonable to ignore this real-world market price information.

Second, while Mr. Barnes proposes to use the PJM market as a proxy for avoided energy costs, he ignores the results of the most recent PJM capacity auction in computing avoided capacity costs and instead uses the capital cost of a NGCC. Even using Mr. Barnes's inflated effective solar capacity value (58.14%), replacing the capital cost of a NGCC in his avoided capacity cost calculation with the most recent PJM capacity auction results ($50/MW-Day) would result in an avoided generation capacity price of $0.00489/kWh ($4.89/MWh).[17] This market-based price result is remarkably consistent with the avoided generation capacity price I recommend using the Current Market Price method. As shown in Table 11 of Supplemental Exhibit DSS-2, avoided generation capacity costs for fixed-tilt and single-axis tracking solar ranges from $4.44/MWh to $4.99/MWh between 2022 and 2024.

Q. What is Mr. Barnes's recommendation regarding the inclusion of possible future CO_2 costs?

A. While he does not calculate a specific value, he seems to be recommending that customers pay now for CO_2 reductions even though no such law or regulation exists today requiring such reductions or attaching a price to CO_2 emissions. As the Commission stated in its order in Case No. 2020-00016 involving the Rhudes Creek Solar PPA, "[T]he Companies' modeling assumed only a zero and high future CO_2 price, without sufficient explanation as to why those assumptions were reasonable and without providing evidence as to the likelihood or expectation of a price on CO_2."[18] Mr. Barnes's testimony provides no evidence to support his recommendation that customers should pay today based on the "expectation of a price on CO_2." As stated in my Supplemental Direct Testimony, my recommended methodology for calculating avoided energy and capacity costs biennially will include future CO_2 costs when they

[17] $4.89/MWh = $50/MW-Day * 365 days * 58.14% * 1.05 / (8,760 hours * 1 MW * 26% capacity factor).
[18] Case No. 2020-00016, Order at 4-5 (Ky. PSC June 18, 2020). Note that the CO_2 prices used in this case were taken from the 2018 IRP.

become known. But today there is no cost to avoid, so including a non-zero CO_2 avoided cost component would unnecessarily increase customers' rates.

Q. What is your view on Mr. Barnes's recommendation to include a separate avoided environmental cost adder?

A. As I stated in my Supplemental Direct Testimony, there is no need for a separate adder because environmental costs are either captured in the avoided energy costs (e.g., limestone and ammonia) or in the need for future capacity. Furthermore, he seems to want to include as a payment for solar energy put on the grid an adder based on the existing ECR rate. This is unreasonable because NMS-2 customers' energy produced to the Companies' grid will avoid *no costs* related to ash pond closure, landfill construction, and effluent limit guideline ("ELG") compliance.

Q. Do you have any concerns with Mr. Barnes's testimony recommendation regarding imputing "jobs benefits" in the price that customers must pay for energy that customer-generators push onto the grid?

A. Yes. I disagree with his recommendation that "Jobs Benefits should be a component of an export rate…." As a professionally trained and practicing economist with background in labor economics, it is my view that including an NMS-2 adder for the "jobs benefits" of solar installers functions as a tax on electricity consumers to protect solar panel installers. As with any protectionist tax or tariff, it is often easier to identify the jobs "saved" or "created" by the tax than the jobs lost because of it or the negative impact on consumers. As the Nobel laureate economist Milton Friedman said:

> The political reason is that the interests that press for protection are concentrated. The people who are harmed by protection are spread and diffused. Indeed the very language shows the political pressure. We call a tariff a protective measure. It does protect; it protects the

> consumer very well against one thing. It protects the consumer against low prices. And yet we call it protection.[19]

In this case, the interests of the Kentucky Solar Industries Association are indeed "concentrated"; its members want to sell more solar panels, particularly on the rooftops of residential and small business customers. Therefore, they are indeed interested in increasing the compensation to potential customers. But including such a protectionist component in NMS-2 rates would only "protect customers against low prices."

Q. Do you agree with Mr. Barnes's recommendation that "avoided ancillary service cost should be a component of the export rate?"

A. No, because generation-based ancillary service costs are included in the retail rates that customers pay due to the fact that customers are paying for 100 percent of the costs of the generation assets. Mr. Barnes seems to want to look at everything through the lens of PJM, in which the market design dissects various operational characteristics of a power plant into separate tariffs (e.g., capacity, ancillary services, energy). The Companies do not operate in such an environment, and their rates are not set according to PJM market design and tariffs. To the extent customer-generators need to be compensated for avoided generation-based ancillary services, they would receive that value via the avoided generation capacity payment. For example, the Rhudes Creek Solar PPA entitles the Companies to utilize all of the generating capabilities of that facility, so the market-based method for calculating avoided capacity costs would reflect that capability. Similarly, the Levelized Cost of a CT avoided capacity cost method (which I do not recommend for solar) includes all of the operational characteristics of the combustion turbine, including those used to provide ancillary

[19] *See* https://www.k-state.edu/landon/speakers/milton-friedman/transcript.html

services. Therefore, requiring customers to pay customer-generators for ancillary services (except via an avoided generation capacity cost component) would result in double charging customers and double-compensating NMS-2 customer-generators.[20]

Q. Do you have any concerns about Mr. Owen's recommendation for addressing future CO_2 emissions?

A. Yes. First, as I have already stated, there is currently no law or regulation that puts a price on CO_2 emissions. Therefore, by definition, there is no avoided cost of such emissions that customers should pay today. Adopting the biennial update process that I recommended in my Supplemental Direct Testimony will capture future CO_2 prices should they be implemented, which then can be addressed in NMS-2 compensation rates when they are adjusted in subsequent base rate cases. Second, using a "social cost of carbon" to set electricity rates is an attempt to make what are currently externalities to the Companies' costs—and are outside the Commission's jurisdiction, as Mr. Conroy explains—a component of NMS-2 compensation. There is no valid rationale for our customers to pay more today based on such a concept, especially at Mr. Owen's recommended 2021 CO_2 price of $51/metric ton of CO_2. This is entirely without basis given current U.S. law and regulations.

Furthermore, his assertion that $51/metric ton is "realistic" because it approximates the carbon price in the European Union Emissions Trading Scheme ignores carbon pricing that is much closer to home. For example, the Regional

[20] The point that customers who pay for generation costs are already paying for generation-based ancillary services is reflected in KU's FERC-approved requirements contracts with the cities of Bardstown and Nicholasville. Section 4.4 of their contracts states that the cities "shall be responsible for paying separately stated Ancillary Services charges under only Ancillary Service Schedule 1." Schedule 1 is for scheduling, system control and dispatch service which are not reflected in the FERC formula rate. The Bardstown and Nicholasville FERC contracts can be found at https://etariff.ferc.gov/TariffSectionDetails.aspx?tid=799&sid=260742 and https://etariff.ferc.gov/TariffSectionDetails.aspx?tid=799&sid=260743, respectively.

Greenhouse Gas Initiative ("RGGI") involves eleven eastern states and, based on recent auction results, puts a price on CO_2 emissions of around $7 / short ton. Kentucky has not joined RGGI and, to my knowledge, is not considering joining. In Kentucky, there is no price on CO_2 today.

Moreover, whatever the benefits of zero carbon emissions in generating electricity may be, if solar is the preferred means of achieving that goal, it is equally well achieved at about $0.03/kWh ($30/MWh) by utility-scale solar as it is by rooftop solar at $0.09/kWh ($90/MWh). There is simply no reason for customers to pay more for the exact same service (i.e., solar-generated electricity) than the market requires.

Q. Do the Companies evaluate the risk of future CO_2 regulations as part of their routine resource planning activities?

A. Yes, but there is a huge difference between evaluating various possible futures and recommending that customers pay today based on a particular view of the future. For example, in Case No. 2011-00375 involving the Companies' request for a CPCN for Cane Run Unit 7, the Sierra Club's witness criticized the Companies for not including a CO_2 price in our analysis of alternatives. My response then was the same as it is today, "It is not prudent to pay a premium today to address unknown and unknowable future greenhouse gas regulations. If CO_2 regulations of the type contemplated by Mr. Chernick [Sierra Club's witness] occur at some future date, then the Companies can evaluate the least-cost options (including renewables) at that time based on the state of technology at that time (which renewable advocates claim will only get better and cheaper)."[21] Had the Commission heeded the recommendation of the Sierra Club

[21] Rebuttal Testimony of David S. Sinclair, Case No. 2011-00375, page 16, lines 3-7.

witness in 2012 and denied the CPCN for Cane Run Unit 7 on the basis of the risk of future CO_2 costs, customers would have paid significantly more for power since 2015 (when Cane Run Unit 7 came on-line) despite the fact there are still no CO_2 regulations as forecasted by their witness. I would add that Cane Run Unit 7 has been the single largest source of the Companies' CO_2 reductions since it came on-line despite the fact that no CO_2 cost was included in the financial justification for the CPCN.

A more recent example of a Commission proceeding where the Companies included potential CO_2 costs as part of their financial analysis was the Companies' application concerning the Rhudes Creek Solar PPA (Case No. 2020-00016). In the Resource Assessment filed in that case,[22] the Companies evaluated the Rhudes Creek proposal and its competitors in a number of scenarios, including one with a CO_2 price. However, while acknowledging that the PPA would reduce future CO_2 emissions, the analysis was clear that absent future CO_2 costs, the PPA was financially justified under most fuel and renewable energy certificate pricing scenarios. Section 3.2 of the Resource Assessment states that one of the assumptions for the early phase of the proposal screening was:

> Zero price for carbon dioxide ("CO_2") emissions. No CO_2 emissions prices were assumed at this early stage in the evaluation given the uncertainty that exists regarding possible future CO_2 regulations. Furthermore, excluding CO_2 emissions prices allowed the Companies to focus the analysis explicitly on avoided energy costs based on known regulations.

As the screening process began to identify potential finalists, the Resource Assessment included a CO_2 price scenario as described in Section 3.4 but with the following caveat:

> The Companies included the high CO_2 emissions price scenarios for illustrative purposes in the absence of actual CO_2 regulations that

[22] Exhibit DSS-2 to the Testimony of David S. Sinclair, Case No. 2020-00016).

> include emissions pricing. For the high CO_2 emissions price scenarios, the analysis did not consider any changes to the composition of the generating fleet that would likely be prudent in a high CO_2 emissions price scenario. This action likely results in a more favorable evaluation of the ibV 100 MW PPA because the avoided cost in a high CO_2 emissions price scenario that includes coal unit retirements would be lower than the case without retirements. In a high CO_2 emissions price environment, natural gas-fired generation or renewables would be expected to replace retiring coal-fired units and these units would dispatch at a lower marginal energy cost compared to the Companies' marginal coal-fired generation. Therefore, the results from the high CO_2 emissions price scenario should be viewed with caution but it is not surprising that solar energy is more attractive with CO_2 pricing.

Therefore, the Companies did not depend on future CO_2 prices as the basis to justify the economics of entering into the Rhudes Creek PPA. The same caution should apply in this case regarding trying to impute a future CO_2 price and assuming no actions would be taken by the Companies to address in this cost should it occur.

Q. Do you agree with Mr. Rábago's recommendation to utilize plant variable O&M in calculating avoided energy cost?

A. Yes. See Supplement Exhibit DSS-1 for how variable O&M was included in the Companies' calculation of avoided energy cost.

Q. Do you agree with Mr. Rábago's recommendation to utilize plant fixed O&M in calculating avoided energy cost?

A. No, such a recommendation is unreasonable. Energy that NMS-2 customers produce onto the grid would have no impact on plant fixed O&M. For example, the number of employees working at a plant, the need for routine maintenance, and the plant's property taxes and insurance would all be unchanged by such energy production.

Q. Based on the rooftop solar installation cost per kWh that you calculated in Supplemental Rebuttal Exhibit DSS-1, how important to the homeowner's economics is the compensation rate for energy that is pushed back on the grid?

A. It is extremely important because, as the table below shows, the total of the variable billing components of residential rates for LG&E and KU are not materially different from the approximately $0.09/kWh ($90/MWh) that is required to cover the cost of a typical installation. This portion of the project value comes from homeowners serving their own load. Thus, even if a homeowner could use 100 percent of her solar energy to serve her own load, the investment in a solar power plant on her roof would be only marginally economical.

Residential (RS) Rate Variable Billing Components ($/kWh)

	KU	LG&E
Energy Charge	0.09727	0.10162
Fuel Adjustment Clause Mechanism	(0.00127)	(0.00143)
Demand Side Management Mechanism	0.00076	0.00104
Environmental Cost Recovery Mechanism	0.00341	0.00229
Off System Sales Mechanism	(0.00001)	(0.00008)
Environmental Cost Recovery Base	0.00171	0.00274
School Tax (3%)	0.00306	0.00319
Total	**0.10492**	**0.10937**

Clearly, the volatility of residential load and solar generation means that it is extremely unlikely that 100 percent of solar generation will be used to serve a homeowner's own load. According to Solar Energy Industries Association ("SEIA"), "On average, only 20-40% of a solar energy system's output ever goes into the grid, and this exported solar electricity serves nearby customers' loads."[23] The table below shows the price that all customers must be willing to pay for energy that customer-generators export to the grid in order for the total project costs to be met. If energy produced to the grid is at the low end of the SEIA range (20%), the price required to cover the cost of the solar array is between $0.019/kWh and $0.037/kWh for exported

[23] https://www.seia.org/initiatives/net-metering.

energy. This is consistent with Mr. Seelye's recommended NMS-2 rate for energy exported to the grid of $0.02319/kWh as presented in his Supplemental Direct Testimony.[24] However, if a customer exports 40 percent of her solar system's output to the grid, then she would require that her neighbors pay between $0.06/kWh and $0.07/kWh – well above their avoided costs.

Price Needed for Energy Exported to Grid to Meet Total Project Costs ($/kWh)

Percent of Total Energy Exported to Grid	KU	LG&E
20%	0.03667	0.01887
30%	0.05942	0.04904
40%	0.07079	0.06412
50%	0.07762	0.07317
60%	0.08217	0.07920
70%	0.08542	0.08351
80%	0.08786	0.08674
90%	0.08975	0.08926

Q. Is there a common theme to the testimony of Mr. Barnes, Mr. Owen, and Mr. Rábago as it relates to their recommendation regarding the price all customers should pay for energy that customer-generators push onto the grid?

A. Yes. They all represent parties that want to install more solar panels on the roofs of homeowners and businesses; therefore, they are seeking to justify the highest NMS-2 compensation possible. This is no different than any other potential supplier that seeks to do business with the Companies. But there is one key difference in this case: when the Companies seek to procure goods and services, they almost always seek competitive bids to ensure that customers who ultimately must pay the bill are receiving

[24] Seelye Supplemental Testimony at 1-2.

the lowest reasonable price. In contrast, Mr. Barnes, Mr. Owen, and Mr. Rábago contend that customers should pay prices far higher than real market alternatives.

<u>Section 4 – LQF and SQF Riders</u>

Q. Do you have any thoughts on Mr. Barnes's recommendations regarding the LQF and SQF riders?

A. As is the case with the NMS-2 rates, Mr. Barnes seems primarily interested in having customers pay more for energy from LQF and SQF generators. He is also interested in incorporating long-term capacity costs into these riders. I believe that the recommendations in my Supplemental Direct Testimony for determining avoided energy and capacity costs, along with the option to lock in 20-year contracts, provide existing and potential SQF and LQF customers compensation that protects the interests of the Companies' one million customers that are paying for the energy and capacity. As the results from the 2019 renewable RFP showed, there are plenty of options available for renewable generation that do not require customers to pay exorbitant SQF and LQF rates to attract similar generation technology. In particular, if the LQF rate is set anywhere near the NMS II rate established in Kentucky Power Company's recent rate case, then, based on our current RFP responses, I would anticipate well over 1,000 MW of solar projects to seek LQF status and force customers to pay for energy at rates that far exceed what could be obtained in the open market.

<u>Section 5 – Summary and Recommendations</u>

Q. Please summarize your recommendations for setting the avoided energy and capacity prices for the NMS-2, SQF, and LQF riders.

A. The overarching principles that drive the Companies' procurement activities are reliability and low costs. A key to implementing those principles in most of our procurement activities is the competitive bidding process whereby the Companies can select the vendor that provides the best price and performance to meet a particular need for goods and services. However, the nature of the NMS-2, SQF, and LQF riders is that there is no competitive bidding process and the Companies have no choice but to purchase their output. Thus, to help ensure that customers do not overpay for energy and capacity from these suppliers, it is vital that the methodology for determining avoided energy and capacity prices for these riders mimics as much as possible the voluntary, competitive procurement process that works so well for customers.

Since 2007, it has been my responsibility to oversee the long-term generation planning and procurement activities for the Companies. In that time, the Companies' analysis has supported decisions to:

- retire over 1,000 MW of coal plants,
- construct the state's first natural-gas fired combined cycle plant (Cane Run unit 7),
- purchase the Bluegrass Generation Station (later terminated because of market power mitigation measures required by FERC),
- seek and withdraw a CPCN application for a combined cycle plant that would have been called Green River unit 5,
- construct the state's first utility-scale solar plant (Brown solar),
- install pollution control equipment on existing coal units, and
- enter into a 20-year PPA for 100 MW of solar generation.

All of these decisions were informed and guided by the Companies' focus on providing reliable, low-cost energy to our customers.

It is my strong recommendation that the same philosophy that has served customers so well throughout my tenure apply to setting avoided energy and capacity costs for the NMS-2, SQF, and LQF riders.

Siting solar panels on a rooftop is not remotely cost-competitive with utility-scale solar in an open field. Thus, the person desiring to install solar panels on their roof must enlist their neighbors in determining the economics of their investment. While solutions exist like installing their own battery storage or contracting for storage services from the utility (e.g., like gas transmission customers often do), all of these only add costs to what is already an economically challenged technology. Thus, to economically justify the installation of rooftop solar, advocates are left to argue that there are numerous extraordinarily high costs that can only be avoided by, in the case of NMS-2 providers, excess energy being exported to the grid or, in the case of SQF and LQF providers, mandatory purchase rates that greatly exceed what could be obtained via a competitive bidding process.

In addition, witnesses such as Mr. Barnes have greatly confused and conflated the operations of a utility in PJM, such as Kentucky Power, with the operations of non-RTO, vertically integrated utilities like the Companies. PJM operates its markets via the tariff setting process in hopes that these tariffs will provide reliable, low cost energy to customers. Hundreds of market participants then react to those tariffs, producing a generation mix that may or may not provide reliable, low-cost energy. On the other hand, the Companies have an obligation to serve their customers' energy needs and thus have a clear responsibility to assemble, operate, and manage a generation portfolio that will provide reliable, low-cost energy to customers. Almost all of Mr. Barnes's recommendations relating to calculating avoided energy, capacity, environmental, CO_2, and ancillary service costs link directly to his misapplication of concepts that might work from a tariff-driven PJM perspective but are clearly incorrect when applied to the Companies' situation.

Finally, it is difficult to avoid concluding that most, if not all, of the recommendations by Mr. Barnes, Mr. Owen, and Mr. Rábago are the direct result of their recognition that a rooftop solar installation needs around $0.09/kWh ($90/MWh) to cover the costs of installation. Thus, at the Companies' current residential retail rates and a possible amount of solar panel energy that will be directly utilized by the NMS-2 customer, the price paid for NMS-2 energy produced to the grid must be up to $0.07/kWh ($70/MWh) or more to make purchasing rooftop solar economical. In other words, all of the recommendations and calculations of Mr. Barnes, Mr. Owen, and Mr. Rábago appear to be rationalizations for why all customers ought to pay more for their electricity in order to promote the installation of rooftop solar; they are not recommendations likely to result in lowest-cost energy for all customers.[25] As the Commission clearly stated regarding the Companies' renewable power agreements with Dow and Toyota, "Kentucky is open for green business, but not at the expense of those businesses' neighbors."[26]

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[25] As Professor Friedman states, "The greatest human capacity we have is not to reason but to rationalize." https://www.k-state.edu/landon/speakers/milton-friedman/transcript.html.

[26] Case No. 2020-00016, Order at 15 (Ky. PSC June 18, 2020).

To be clear, the Companies' fully support customers' right to install their own solar panels. But their decision to do so should not require their neighbors to purchase energy at prices that exceed <u>actual</u> avoided costs.

I strongly urge the Commission to adopt the methods and prices that I proposed in my Supplemental Direct Testimony as the basis for the NMS-2, SQF, and LQF riders.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of August 2021.

Notary Public

Notary Public ID No. KYNP32193

My Commission Expires:

06-25-2025

Levelized Cost of Residential and Utility-Scale Solar

The levelized cost of residential and utility-scale solar arrays is computed in $/kWh as a function of the cost and capacity factor metrics in Table 1 from the National Renewable Energy Laboratory's 2020 Annual Technology Baseline ("NREL 2020 ATB"). Other input assumptions are summarized in Table 2.

Table 1: Solar Cost and Capacity Factor (Source: NREL 2020 ATB; 2022 Installation; 2018 Dollars)

Item	Residential Solar	Utility-Scale Solar
Capital Cost ($/kW)	2,340	1,224
Operating and Maintenance ("O&M") Cost ($/kW-Year)	17.55	14.64
Capacity Factor (%)	16.6%	27.9%
Weighted Average Cost of Capital (WACC) (%)	4.37%	4.24%

Table 2: Other Assumptions

Item	Value
Investment Tax Credit	26%
Inflation	2%
Array Life	30 Years
Solar Output Degradation	0%

Compared to a residential solar array, the capital and O&M cost of a utility-scale solar array is lower on a $/kW basis, and the annual energy output (as measured by capacity factor) is higher. The impacts of these differences on levelized cost are summarized in Table 3. Based on NREL cost and capacity factor assumptions, the levelized cost of residential solar is $0.0913/kWh. This cost is reduced to $0.0543/kWh when a residential solar array is assumed to operate at a utility-scale solar array's capacity factor (27.9%). With both utility-scale capacity factor and cost, the levelized cost is $0.0315/kWh. Differences in NREL's assumptions for WACC does not materially affect the levelized cost.

Table 3: Levelized Costs ($/kWh)

Item	Residential Solar	Residential Solar w/ Utility-Scale Capacity Factor	Utility-Scale Capacity Factor and Cost w/ Residential Discount Rate	Utility-Scale Solar
Capacity Factor	Residential Solar	Utility-Scale Solar	Utility-Scale Solar	Utility-Scale Solar
Capital and O&M Costs	Residential Solar	Residential Solar	Utility-Scale Solar	Utility-Scale Solar
WACC	Residential Solar	Residential Solar	Residential Solar	Utility-Scale Solar
Levelized Cost ($/kWh)	**0.0913**	**0.0543**	**0.0315**	**0.0312**

All-Electric Residential Load & Solar Generation Profile

Fifteen-minute load data from a week in January 2020 and July 2020 are displayed in Figures 1a and 2a, respectively, for a typical all-electric AMI customer (~17,000 kWh/year). Figures 1b and 2b contain estimated fifteen-minute generation data for the same weeks for a typical 8 kW residential solar array.[1] For the winter week, the correlation between load and generation for all hours is -0.09, and for the summer week the correlation is -0.03. For hours with solar production, the winter week correlation is -0.14, and for the summer week it is -0.09.

[1] The solar generation data was created by scaling Solar Share generation for these weeks to reflect the output from an 8 kW AC array. The capacity of Solar Share in 2020 during these weeks was 450 kW. Therefore, actual Solar Share generation was multiplied by the ratio of 8 kW and 450 kW to estimate the output of an 8 kW residential array.

Figure 1a: Fifteen-Minute Load for Typical All-Electric Customer (Winter)

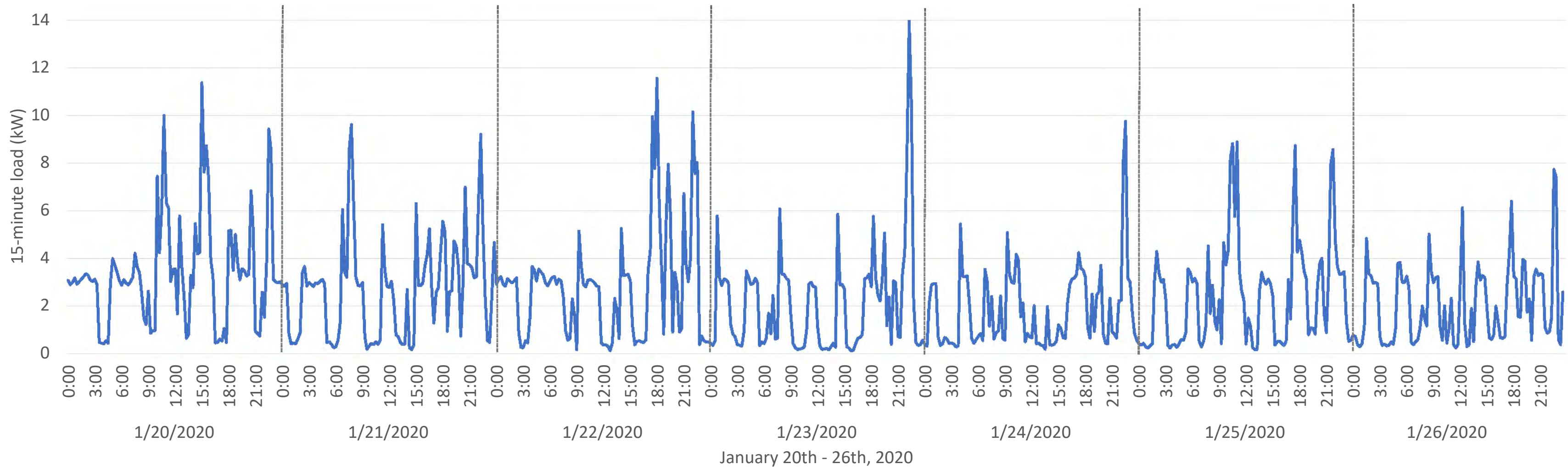


Figure 1b: Estimated Generation for Residential Solar Array (Winter)

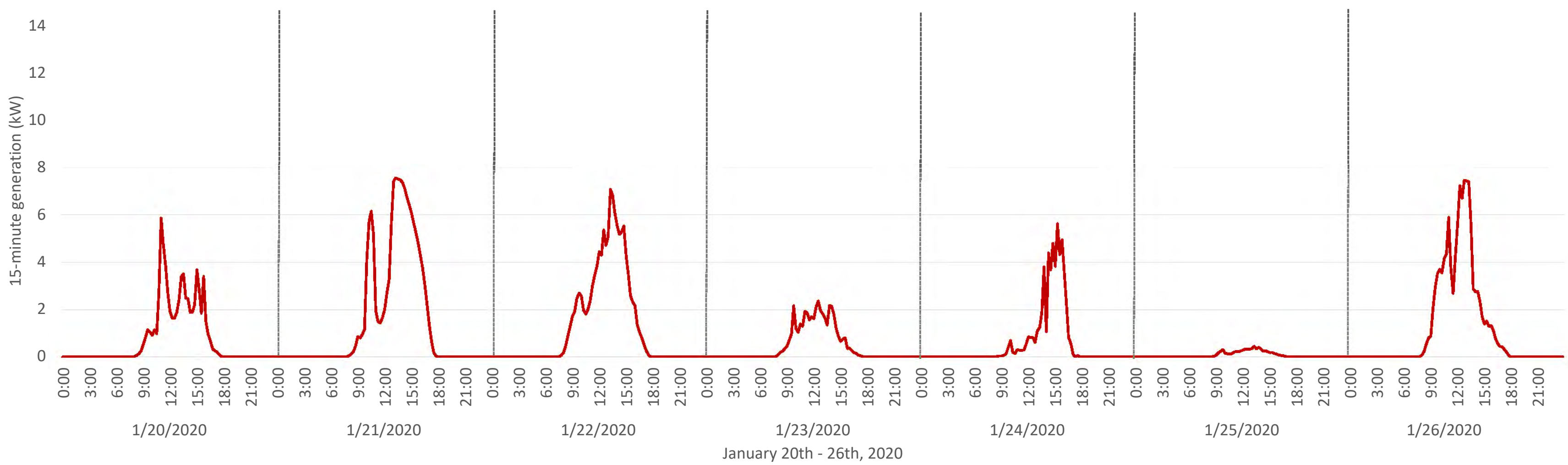


Figure 2a: Fifteen-Minute Load for Typical All-Electric Customer (Summer)

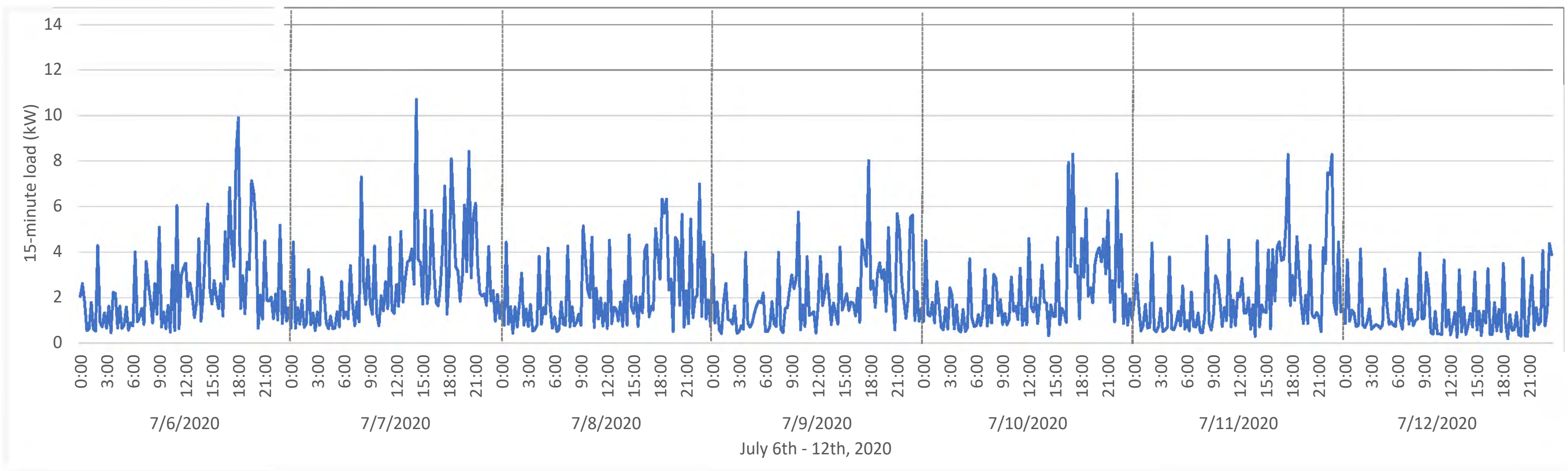
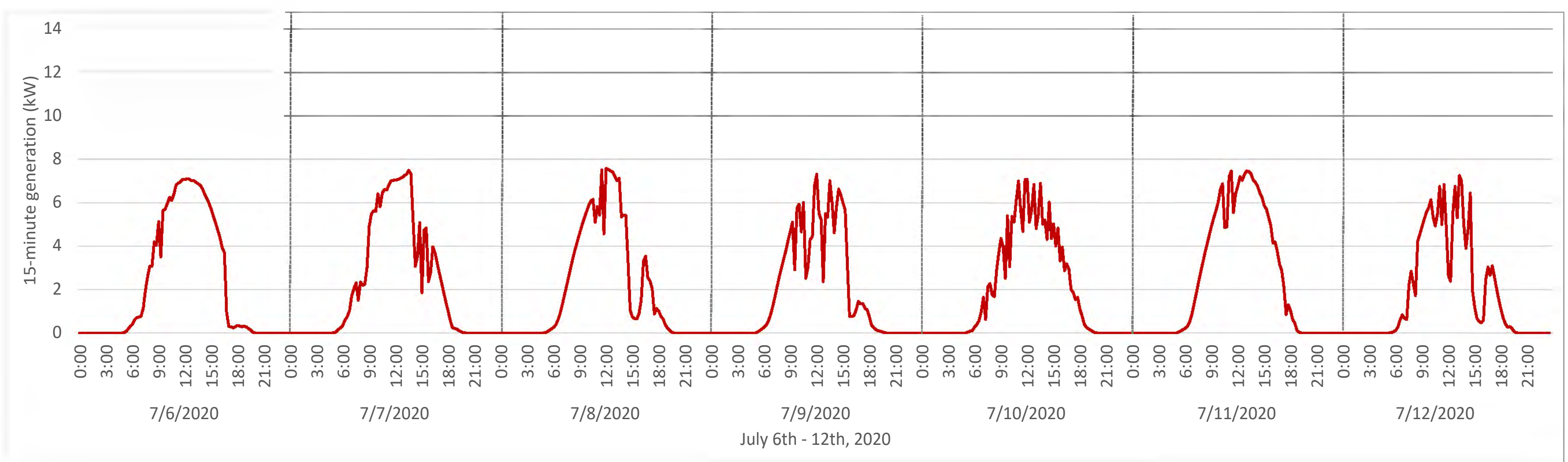


Figure 2b: Estimated Generation for Residential Solar Array (Summer)



2018 IRP Reserve Margin Analysis

PPL companies

Generation Planning & Analysis

September 2018

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1 Executive Summary

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. While the results of this analysis are generally communicated in the context of a summer peak reserve margin, the mathematics – like past reserve margin analyses – assess the Companies' ability to reliably serve customers in all hours.

Using the same methodology as the 2014 IRP, the 2018 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2021 over a wide range of summer peak reserve margins to identify the optimal generation mix for customers. With the Companies' existing resources, the forecasted summer peak reserve margin in 2021 is 23.5 percent in the base energy requirements forecast scenario. To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirement of their small-frame simple-cycle combustion turbines ("SCCTs"), the Demand Conservation Program ("DCP"), one or more Brown 11N2 SCCTs, and Brown 3.[1] Similarly, to determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity to the generation portfolio.

The results of this analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2021. In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources. With the exception of the DCP, the reliability and generation production cost benefit for each of the Companies' marginal resources clearly exceeds the costs that would be saved by retiring these units. Consistent with the analysis supporting the Companies' December 2017 DSM filing, the DCP is only marginally favorable. However, given uncertainties moving forward related to load and environmental regulations, and considering physical reliability guidelines, the DCP should be continued at least in the near-term.

The target summer reserve margin range established in the 2014 IRP Reserve Margin analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 loss-of-load event ("1-in-10 LOLE") physical reliability guideline. Based on the Companies' current load forecast and resources, the reserve margin required to meet this guideline is approximately 25 percent.[2] To determine the minimum of the target reserve margin range, the Companies estimated the increase in load that would result in the addition of generation resources. All

[1] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11.

[2] The increase from 21 percent to 25 percent is driven primarily by an increase in the assumed variability of winter peak demands. The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015).

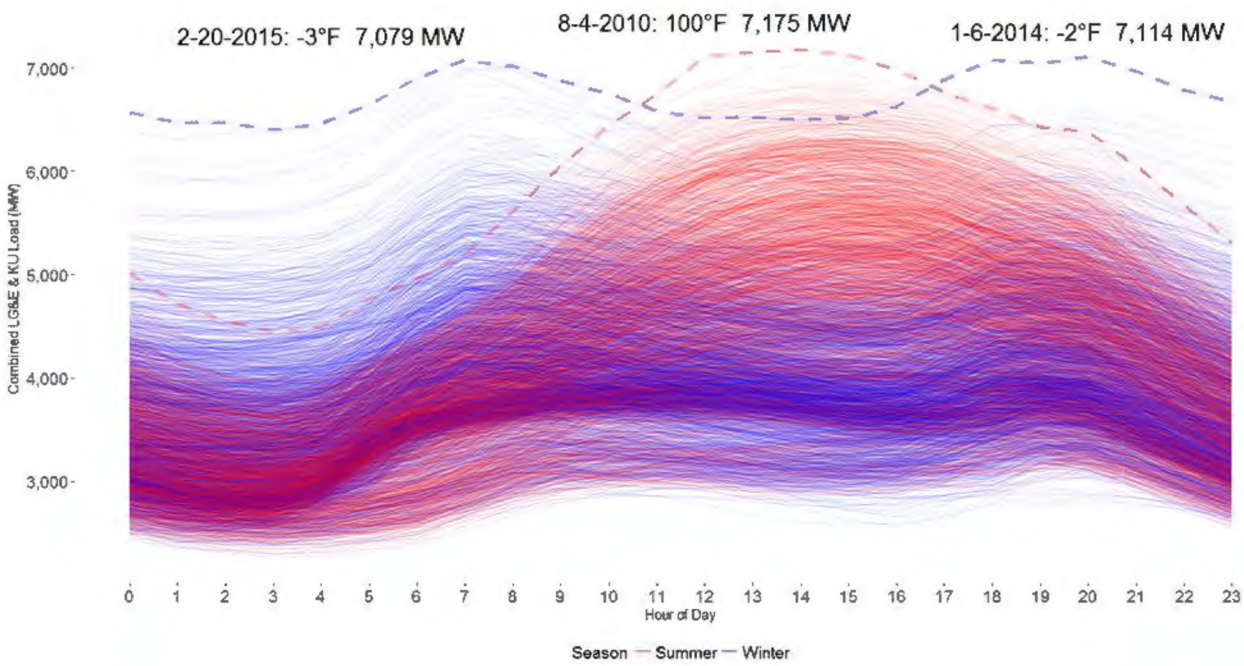
other things equal, if the Companies' load increases by 300 to 400 MW, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. With this load increase, the Companies' reserve margin would end up being 16 to 18 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

2 Introduction

An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015).

Figure 1 contains the Companies' hourly load profiles for every day over the past ten years. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

Figure 1: Hourly Load Profiles, 2008-2017



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 2 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher. To serve customers in every moment, the Companies must have a portfolio of generation resources that can produce power when customers want it.

Figure 2: Four-Second Demands, 5:00-7:00 PM on January 6, 2014

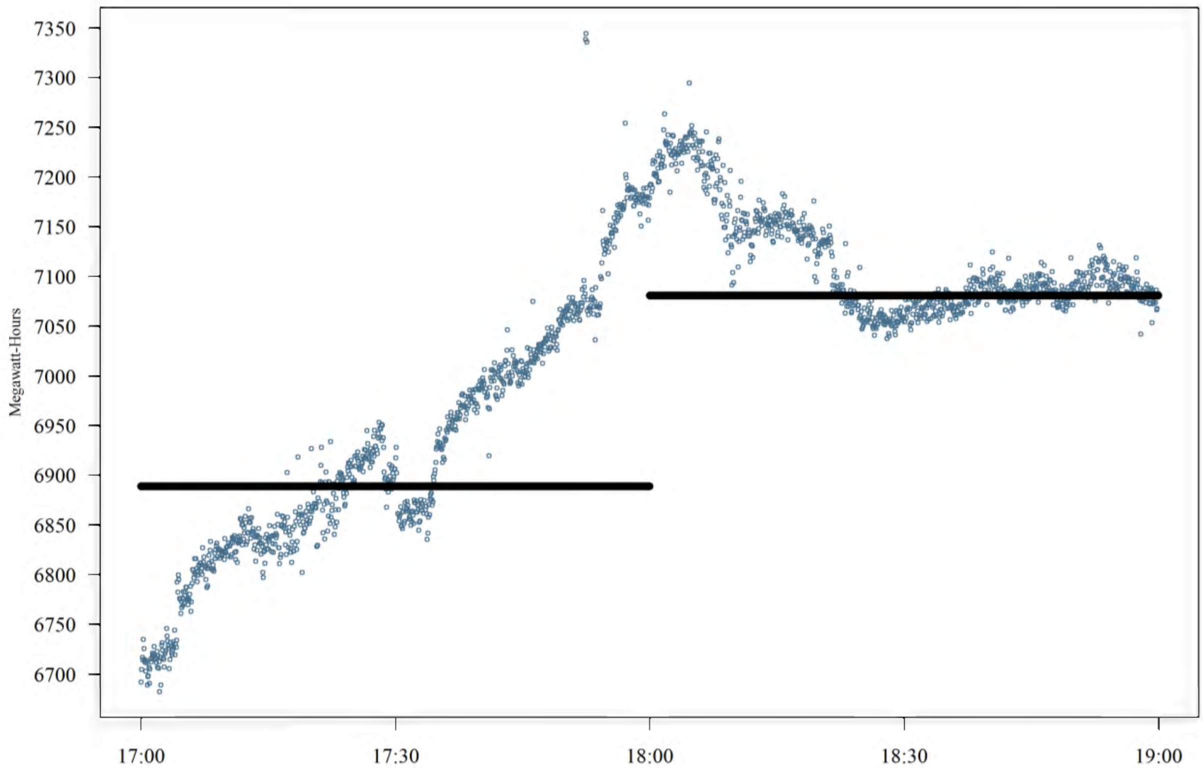


Table 1 contains the Companies' reserve margin forecast with planned retirements in the base energy requirements forecast scenario. Summer peak demand decreases from 2018 to 2019 primarily due to the departure of eight municipal customers. Load reductions associated with the Companies' DSM programs reflect changes to DSM programs approved in the Companies' recent DSM filing in Kentucky.[3] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years. Beginning in 2021, the forecasted reserve margin for the base energy requirements scenario ranges from 23 percent to 24 percent.

[3] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.

Table 1: Peak Demand and Resource Summary (Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Summer Peak Demand	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Demand	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[4]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[5]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

Different types of generation resources play different roles in serving customers. The Companies' coal units have real-time load-following capabilities and can be brought on-line with less than a day's notice to serve load. With higher ramp rates and shorter start times, the Companies' natural gas combined-cycle ("NGCC") unit and large-frame SCCTs can respond to significant load swings and can be committed with little notice in response to forced outages. The Companies' small-frame SCCTs and demand-side resources have no load-following capabilities; while they can be committed in response to forced outages they require more notice than large-frame SCCTs or NGCC units and their small size and high cost limit their usefulness in dealing with forced outages. Finally, the Companies' renewable resources have little to no fuel or emissions costs, but they have no load-following capabilities and their availability during peak load conditions is uncertain due to their intermittent fuel source. The Companies' resource planning decisions must ensure their generation portfolio has the full range of operational capabilities and attributes needed to serve customers in every moment.

The following sections summarize the Companies' reserve margin analysis. Section 3 discusses the analysis framework. Section 4 provides a summary of key inputs and uncertainties in the analysis. Finally, Section 5 provides a summary of the analysis results.

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[4] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.

[5] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

3 Analysis Framework

Figure 3 illustrates the costs and benefits of adding capacity to a generation portfolio.[6] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable) but fixed capacity costs increase. In their reserve margin analysis, the Companies' evaluate these costs and benefits over a range of reserve margins. The reserve margin at which the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin.

Figure 3: Costs and Benefits of Generation Capacity (Illustrative)

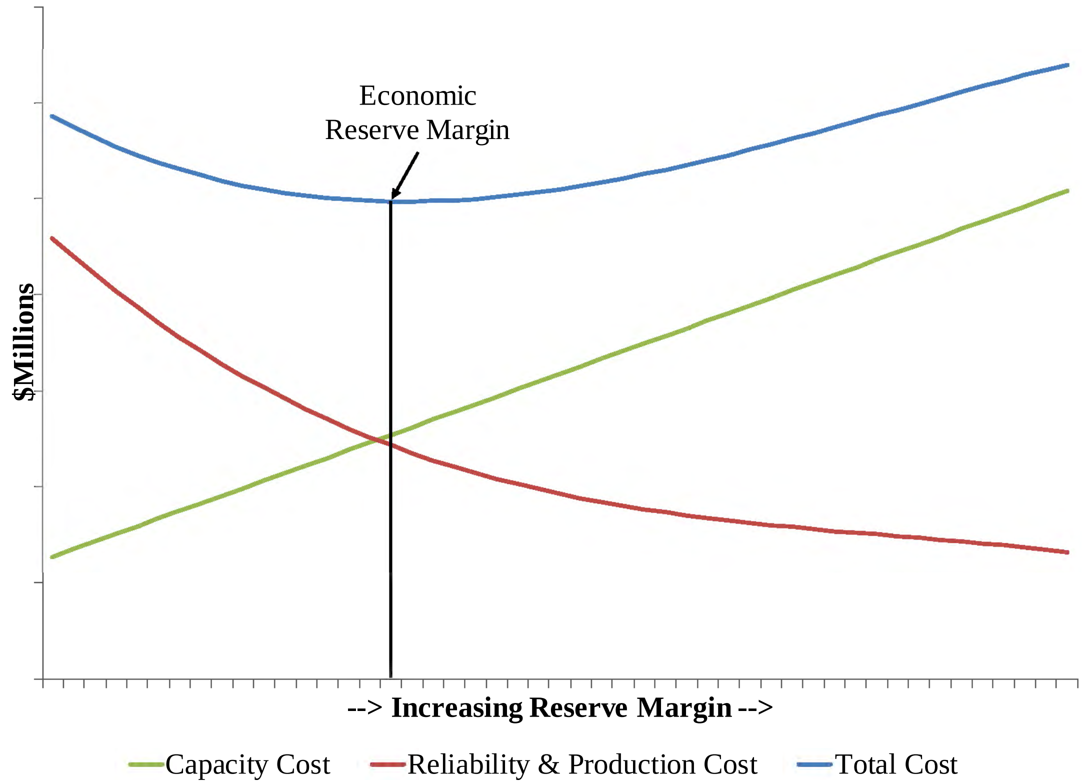

Figure 4 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is not surprising; in an extreme case where the cost of capacity is zero, the Companies would add capacity until the value of adding capacity reduced to zero.[7]

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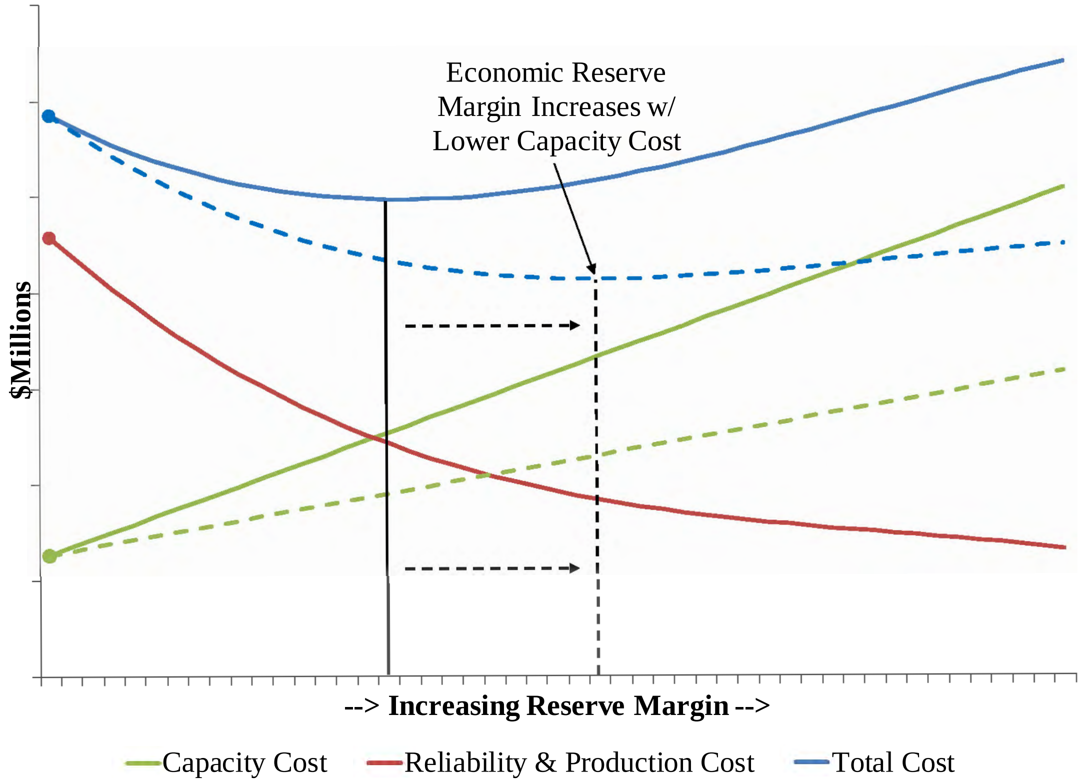
[6] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

[7] In Figure 4, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

Figure 4: Economic Reserve Margin and Capacity Cost (Illustrative)



For new capacity, the capacity cost includes the fixed costs required to operate and maintain the unit as well as the revenue requirements associated with constructing the unit. When a portion of the evaluated reserve margin range falls below the Companies' forecasted reserve margin, the Companies must consider the costs and benefits of retiring their existing marginal resources to evaluate this portion of the range. When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs. An existing unit's ongoing fixed operating and maintenance costs are its stay-open costs.

The Companies evaluated reserve margins ranging from 12 to 24 percent in their 2014 IRP Reserve Margin Analysis. As this analysis was being developed, the Companies were evaluating the addition of Green River 5 (670 MW) at the Green River Generating Station. Without Green River 5, the Companies' reserve margin in 2018 was forecast to be 12 percent. Therefore, their reserve margin analysis evaluated only the costs and benefits of adding new capacity to their generation portfolio.

In the 2018 IRP base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. Therefore, to evaluate a similar range of reserve margins using the same methodology, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. The cost of continuing to operate each of the Companies' marginal resources is currently less than the cost of adding and operating new resources.

In North America, the most commonly used physical reliability guideline is the 1-in-10 LOLE guideline. Systems that adhere to this guideline are designed such that the probability of a loss-of-load event is one event in ten years. In addition to the economic reserve margin, this analysis considers the resources needed to meet this guideline. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to estimate reliability and generation production costs as well as the expected number of loss-of-load events in ten years ("LOLE") over a range of reserve margin levels. ELDCM estimates LOLE and reliability and generation production costs based on an equivalent load duration curve.[8] SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011 and 2014 IRPs. SERVM models the availability of generating units in more detail than ELDCM but ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios. Given the differences between the models, their results should be consistent but not identical.

Key inputs to SERVM and ELDCM include load, unit availability, the ability to import power from neighboring regions, and other factors. SERVM separately models the ability to import power from each of the Companies' neighboring regions based on the availability of generation resources and transmission capacity in each region. In ELDCM, the Companies' ability to import power from neighboring regions is modeled as a single "market" resource where the availability of the resource is determined by the sum of available transmission capacity in all regions. Key analysis inputs and uncertainties are discussed in the following section.

4 Key Inputs and Uncertainties

Several factors beyond the Companies' control impact the Companies' planning reserve margin and their ability to reliably serve customers' energy needs. The key inputs and uncertainties considered in the Companies' reserve margin analysis are discussed in the following sections.

4.1 Study Year

The study year for this analysis is 2021. The municipal departure, the end of the Bluegrass Agreement, and the retirements of Brown 1 and Brown 2 are planned to occur in 2019. Zorn 1 is assumed to retire on January 1, 2021. 2021 is the first full year after these events.

4.2 Neighboring Regions

The vast majority of the Companies' off-system purchase transactions are made with counterparties in MISO, PJM, or TVA. SERVM models load and the availability of excess capacity from the portions of the MISO, PJM, and TVA control areas that are adjacent to the Companies' service territory.[9] These portions of MISO, PJM, and TVA are referred to as "neighboring regions." The following neighboring regions are modeled:

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[8] See https://www-pub.iaea.org/MTCD/Publications/PDF/TRS1/TRS241_Web.pdf beginning at page 219 for the modeling framework employed by ELDCM.

[9] As discussed previously, the ability to import power from neighboring regions is modeled as a single "market" resource in ELDCM.

- MISO-Indiana – includes service territories for all utilities in Indiana as well as Big Rivers Electric Corporation in Kentucky.
- PJM-West – refers to the portion of the PJM-West market region including American Electric Power ("AEP"), Dayton Power & Light, Duke Ohio/Kentucky, and East Kentucky Power Cooperative service territories.
- TVA – TVA service territory.

Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of developing a target reserve margin range for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 17.1% (MISO[10]), 15.8% (PJM[11]), and 15% (TVA[10]).[12]

4.3 Generation Resources

The unit availability and economic dispatch characteristics of the Companies' generating units are modeled in SERVM and ELDCM. SERVM also models the generating units in neighboring regions.

4.3.1 Unit Availability Inputs

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. Table 2 contains a summary of the Companies' generating resources along with their assumed equivalent forced outage rates ("EFORs"). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio and not materially different from the availability of neighboring regions' units today.

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[10] See NERC's "2018 Summer Reliability Assessment" at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf.
[11] See PJM's "2017 PJM Reserve Requirement Study" (October 12, 2017) at https://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx.
[12] In the reserve margin analysis, adjustments were made to the neighboring regions' generating portfolios as needed to reflect planned retirements and meet the neighboring regions' target reserve margins.

Table 2: 2021 LG&E/KU Generating Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW)[13]	EFOR
Brown 3	Coal	415	5.7%
Brown 5	SCCT	130	9.9%
Brown 6	SCCT	146	9.9%
Brown 7	SCCT	146	9.9%
Brown 8	SCCT	120	9.9%
Brown 9	SCCT	120	9.9%
Brown 10	SCCT	121	9.9%
Brown 11	SCCT	121	9.9%
Brown Solar	Solar	8	2.5%
Cane Run 7	NGCC	662	3.0%
Cane Run 11	Small-Frame SCCT	14	50.0%
Dix Dam 1-3	Hydro	32	N/A
Ghent 1	Coal	474	5.2%
Ghent 2	Coal	484	5.2%
Ghent 3	Coal	480	5.2%
Ghent 4	Coal	477	5.2%
Haefling 1-2	Small-Frame SCCT	24	50.0%
Mill Creek 1	Coal	299	5.2%
Mill Creek 2	Coal	296	5.2%
Mill Creek 3	Coal	390	5.2%
Mill Creek 4	Coal	476	5.2%
Ohio Falls 1-8	Hydro	64	N/A
OVEC-KU	Power Purchase	47	N/A
OVEC-LG&E	Power Purchase	105	N/A
Paddy’s Run 11	Small-Frame SCCT	12	50.0%
Paddy’s Run 12	Small-Frame SCCT	23	50.0%
Paddy’s Run 13	SCCT	147	9.9%
Trimble County 1 (75%)	Coal	368	5.2%
Trimble County 2 (75%)	Coal	546	9.3%
Trimble County 5	SCCT	159	5.7%
Trimble County 6	SCCT	159	5.7%
Trimble County 7	SCCT	159	5.7%
Trimble County 8	SCCT	159	5.7%
Trimble County 9	SCCT	159	5.7%
Trimble County 10	SCCT	159	5.7%
CSR	Interruptible	141	N/A

4.3.2 Fuel Prices

The forecasts of natural gas and coal prices for the Companies’ generating units are summarized in Table 3 and Table 4. Fuel prices in neighboring regions were assumed to be consistent with the Companies’

[13] Projected net ratings as of 2021. OVEC’s capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW. The ratings for Brown Solar, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

fuel prices. The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs.

Table 3: 2021 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)

Month	Value
1	3.008
2	2.983
3	2.904
4	2.638
5	2.614
6	2.641
7	2.670
8	2.684
9	2.682
10	2.710
11	2.773
12	2.919

Table 4: 2021 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

Station	Value
Brown	2.593
Ghent	2.008
Mill Creek	2.055
Trimble County – High Sulfur	2.017
Trimble County – PRB	2.292

4.3.3 Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 5 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[14] However, because the Companies can curtail CSR customers only in hours when more than 10 of the Companies' large-frame SCCTs are being dispatched, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon. The total assumed capacity of the CSR program is 141 MW.

[14] See KU's Electric Service Tariff at https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf and LG&E's at https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf.

Table 5: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
Air Liquide	1.0
ASRC[15]	1.3
Carbide Industries	21.4
CEMEX	17.3
Chemours	1.9
Fort Knox[15]	0
Infiltrator Systems	2.5
JBS Swift[15]	0
LSC Communications	3.2
Matheson Tri-Gas	5.1
North American Stainless	64.1
Old Castle	0.5
River View Coal	15.5
Roberts Brothers	2.5
Rohm & Haas[15]	0.6
UPS[15]	0
Warrior Coal Mining	4.0
Webster Co. Coal	0
Total	140.9

4.4 Available Transmission Capacity

Available transmission capacity ("ATC") determines the amount of power that can be imported from neighboring regions to serve the Companies' load and is a function of the import capability of the Companies' transmission system as well as the export capability of the system from which the power is purchased. For example, to purchase 50 MW from PJM, the Companies' transmission system must have at least 50 MW of available import capability and PJM must have at least 50 MW of available export capability. If PJM only has 25 MW of export capability, total ATC is 25 MW.

The Companies' import capability is assumed to be negatively correlated with load. Furthermore, because weather systems impact the Companies' service territories and neighboring regions similarly, the export capability from neighboring regions is oftentimes also limited when the Companies' load is high. Table 6 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2016 and 2017 and the winter months of 2017 and 2018. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 45% of the time.

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[15] These customers have expressed interest in the CSR but have not yet begun service under this rider.

Table 6: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	95	45%
1 – 199	31	15%
200 - 399	5	2%
400 - 599	4	2%
600 - 799	10	5%
800 - 999	21	10%
>= 1,000	45	21%
Total	211	

During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM and SERVM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time. Alternative ATC scenarios are also considered to understand the impact of this input assumption on the analysis.

4.5 Load Modeling

Uncertainty in the amount and timing of customers' utilization of electricity is a key consideration in resource planning. Uncertainty in the Companies' load is modeled in SERVM and ELDCM. SERVM also models load uncertainty in neighboring regions. Table 7 summarizes the peak demand forecast for the Companies' service territories and neighboring regions in 2021. The Companies' peak demand is taken from the base energy requirements forecast scenario and reflects the impact of the Companies' DSM programs. The forecasts of peak demands for MISO-Indiana, PJM-West, and TVA were taken from RTO forecasts and NERC Electricity Supply and Demand data.

Table 7: Peak Load Forecasts for 2021

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	6,350	19,302	36,121	29,811
Target Reserve Margin	N/A	17.1%	15.8%	15%

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in each month of every year. In a given month, weather on the peak day is assumed to be the average of weather on the peak day over the past 20 years. While this is a reasonable assumption for long-term resource planning, weather from one month and year to the next is never the same. The frequency and duration of severe weather events within a year have a significant impact on load shape and reliability and generation production costs. For this reason, the Companies produced 45 hourly demand forecasts for 2021 based on actual weather in each of the last 45 years.

Table 8 summarizes the distributions of summer and winter peak demands for the Companies' service territory and coincident demands in the neighboring regions. Because each set of coincident peak demands is based on weather from the same weather year, SERVM captures weather-driven covariation in loads between the Companies' service territories and neighboring regions to the extent weather is correlated.

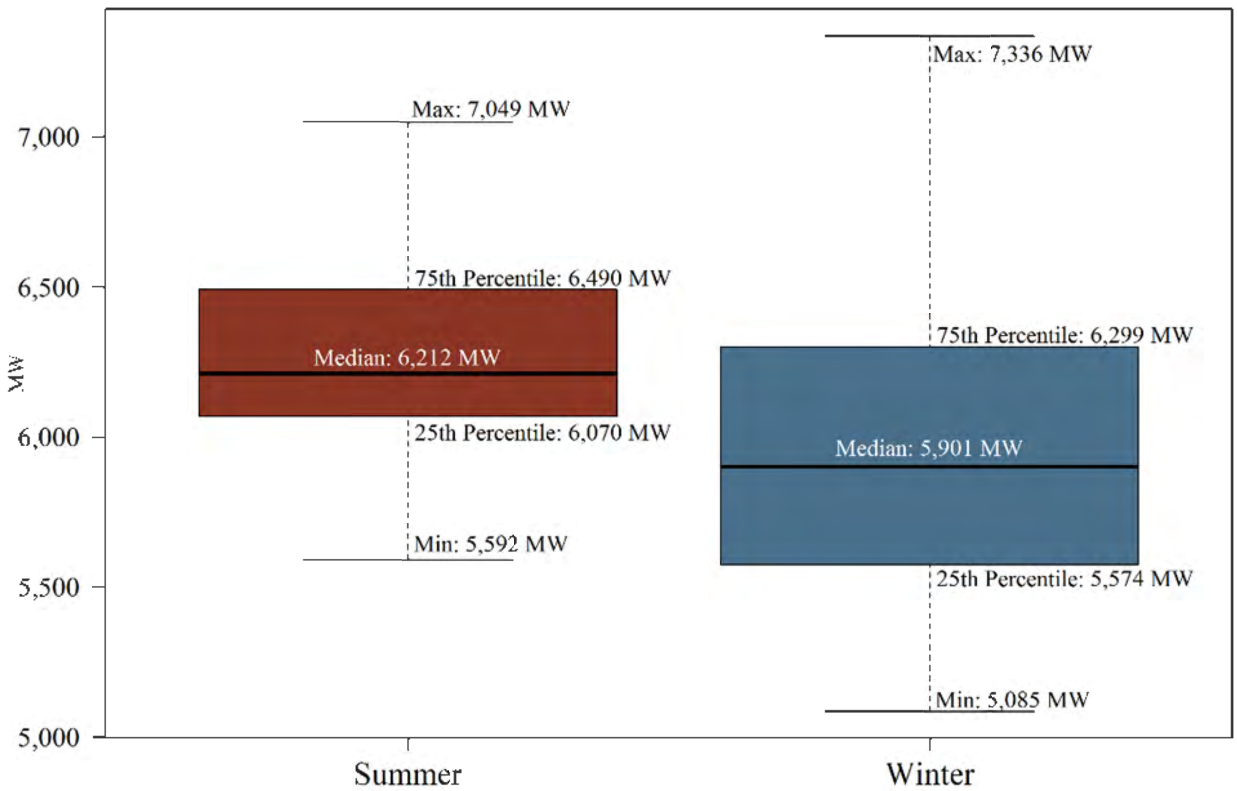
Table 8: Summer and Winter Peak Demand Forecasts

LG&E/ KU Load	Summer					Winter				
			Coincident Peak Demand in Neighboring Regions					Coincident Peak Demand in Neighboring Regions		
	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA
Max	1983	7,049	19,880	36,987	30,648	1985	7,336	16,322	38,359	33,450
75th %-ile	2017	6,490	18,933	33,786	30,024	1986	6,299	15,840	33,667	32,181
Median	2001	6,212	17,665	32,985	27,743	2010	5,901	16,049	32,913	31,003
25th %-ile	1996	6,070	17,610	33,631	27,472	1991	5,574	15,967	34,649	26,357
Min	1974	5,592	17,509	31,742	25,109	1990	5,085	14,886	34,004	25,936

Because the ability to purchase power from neighboring regions oftentimes depends entirely on the availability of transmission capacity, load uncertainty in the Companies' service territories has a much larger impact on resource planning decisions than load uncertainty in neighboring regions. Figure 5 plots the distributions of summer and winter peak demands in the Companies' service territories. The Companies' median peak demand is higher in the summer, but the variability in peak demands – as experienced over the past five years – is much higher in the winter.[16] This is largely due to the fact that electric heating systems with heat pumps consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered.

[16] The distributions in Table 8 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 141 MW in 2021. The maximum winter peak demand (7,336 MW) is forecasted based on the weather from January 20, 1985 when the average temperature was -8 degrees Fahrenheit and the low temperature was -16 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex event was 7,114 MW and the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

Figure 5: LG&E and KU Peak Demands, 2021



4.6 Marginal Resource Costs

In the base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. To evaluate reliability and cost at lower and higher reserve margins, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. Furthermore, because different types of resources have different operating capabilities, the Companies separately evaluated the retirement of marginal baseload and marginal peaking resources.

Table 9 contains stay-open costs (i.e., ongoing fixed operating and maintenance costs) and average energy costs for the Companies' baseload generation units that are 40 or more years old, the Companies' peaking units that are 15 or more years old, and the Companies' Demand Conservation Programs ("DCP").[17] The Companies' peaking units include large-frame and small-frame SCCTs; small-frame SCCTs include Haefling 1 and 2, Paddy's Run 11 and 12, and Cane Run 11. The stay-open costs in Table 9 are presented in 2021 dollars and are computed based on stay-open costs over an eight-year

[17] The Demand Conservation Programs include the Residential and Non-Residential Demand Conservation Programs. These programs are the Companies' only dispatchable demand-side management programs. The Companies did not evaluate the Curtailable Service Rider because the elimination of this rider would have no impact on total revenue requirements.

maintenance cycle from 2020 to 2027.[18] Similar peaking units (e.g., Brown 5, 8, 9, 10, & 11) are grouped together. Average energy costs are computed based on the base fuel prices in Section 4.3.2.

Table 9: Marginal Resource Costs (2021 Dollars)

	Resource	Stay-Open Cost ($/kW-year)	Average Energy Cost ($/MWh)	Stay-Open Costs + Average Energy Costs ($/MWh)
Baseload	Brown 3	87.3	34	84
	Ghent 1	84.1	24	41
	Ghent 2	65.1	22	32
	Mill Creek 1	71.3	23	35
	Mill Creek 2	81.0	23	37
	Mill Creek 3	78.0	24	37
	OVEC	92.3	25	47
Peaking	Brown 5, 8, 9, 10, & 11	11.5	41	79
	Brown 6 & 7	20.5	31	66
	Paddy's Run 13	16.3	30	52
	Trimble County 5 & 6	29.7	30	64
	Small-Frame SCCTs	3.4	80	406
DSM	Demand Conservation Programs ("DCP")	25.6	145	460

To evaluate reserve margins less than 23.5 percent, the sum of stay-open and average energy costs in Table 9 was used to determine the order in which certain baseload and peaking resources would be considered for retirement. For example, based on these costs, the Companies assumed that the DCP would be retired first and the small-frame SCCTs would be retired second. The annual stay-open costs for these resources (expressed on a $/kW-year basis) are not as high as other resources, but the sums of stay-open and average energy costs (expressed on a $/MWh basis) are much higher due to their high dispatch cost which results in limited utilization. In addition, customer participation in the DCP is expected to decline moving forward and the small-frame SCCTs are far more likely to experience a catastrophic failure because of their age.[19] It would not be prudent to retire another unit with the assumption that these resources could be more heavily utilized.

Based on the sum of stay-open and average energy costs in Table 9, Brown 3 ("BR3") and OVEC are the Companies' marginal baseload units and, besides the small-frame SCCTs, Brown 5, 8, 9, 10, and 11 ("BR5, BR8, BR9, BR10, and BR11") are the Companies' marginal peaking units. The stay-open cost for Brown 3 is consistent with other baseload units but its average generation cost is higher primarily due to the high cost of rail transportation for coal delivered to the Brown station. Despite this fact, the ability

[18] An example of this calculation is included in Appendix A: Stay-Open Cost Example.

[19] The Companies do not plan for major maintenance on their small-frame SCCTs. These units range between 48 and 50 years old, have relatively inefficient heat rates compared to large-frame SCCTs, and are only operated on a limited basis.

to shift generation to Brown 3 from other coal units is a valuable alternative for controlling fleet-wide emissions.[20]

To evaluate reserve margins greater than 23.5 percent, the analysis weighed the costs and benefits of adding new SCCT capacity. The cost of new SCCT capacity is taken from the 2018 IRP Resource Screening Analysis and is summarized in Table 10 in 2021 dollars. Not surprisingly, the carrying charge for new SCCT capacity ($123/kW-year) is higher than the stay-open costs for existing capacity ($3-92/kW-year) since their construction cost is considered sunk.

Table 10: SCCT Cost (2021 Dollars)[21]

Input Assumption	Value
Capital Cost ($/kW)	964.5
Fixed Charge Rate	9.0%
Fixed O&M ($/kW-yr)	13.3
Firm Gas Transport ($/kW-yr)	23.6
Carrying Charge ($/kW-yr)	123.3

4.7 Cost of Unserved Energy (Value of Lost Load)

The impacts of unserved energy on business and residential customers include the loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting.

For this study, unserved energy costs were derived based on information from four publicly available studies.[22] All studies split customers into residential, commercial, and industrial classes which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2021 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy was calculated to be $18.30/kWh.

Table 11 shows how the numbers were derived. The range for residential customers varied from $1.40/kWh to $3.50/kWh. The range for commercial customers varied from $24.70/kWh to

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[20] Brown 3 has been retrofitted with flue-gas desulfurization equipment designed to remove 98% of the unit's sulfur dioxide emissions, selective catalytic reduction designed to remove 90% of the unit's emissions of nitrogen oxides, a fabric filter baghouse designed to remove 99.5% of the unit's particulate matter, and an overall air quality control system designed to achieve 89% mercury removal.

[21] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[22] "Estimated Value of Service Reliability for Electric Utility Customers in the Unites States," Ernest Orlando Lawrence Berkeley National Laboratory, June 2009;
"Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans," Christensen Associates Energy Consulting, August 15, 2005;
"A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," Ernest Orlando Lawrence Berkeley National Laboratory, November 2003;
"Value of Lost Load," University of Maryland, February 14, 2000.

$36.60/kWh while industrial customers varied from $12.80/kWh to $29.70/kWh. Not surprisingly, commercial and industrial customers place a much higher value on reliability given the impact of lost production and/or product. The range of system cost across the four studies is approximately $7.50/kWh.

Table 11: Cost of Unserved Energy (2021 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.60	1.40	3.50	3.00
Commercial	36%	36.60	33.30	24.70	25.70
Industrial	30%	21.10	29.70	12.80	25.70
System Cost of Unserved Energy		20.10	21.40	13.90	18.00
	Customer Class Mix	**Min $/kWh**	**Mean $/kWh**	**Max $/kWh**	**Range $/kWh**
Residential	34%	1.40	2.40	3.50	2.10
Commercial	36%	24.70	30.10	36.60	11.90
Industrial	30%	12.80	22.30	29.70	16.90
Average System Cost of Unserved Energy			18.30		

4.8 Spinning Reserves

Based on the Companies' existing resources, they are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements.

4.9 Reserve Margin Accounting

The following formula is used to compute reserve margin:

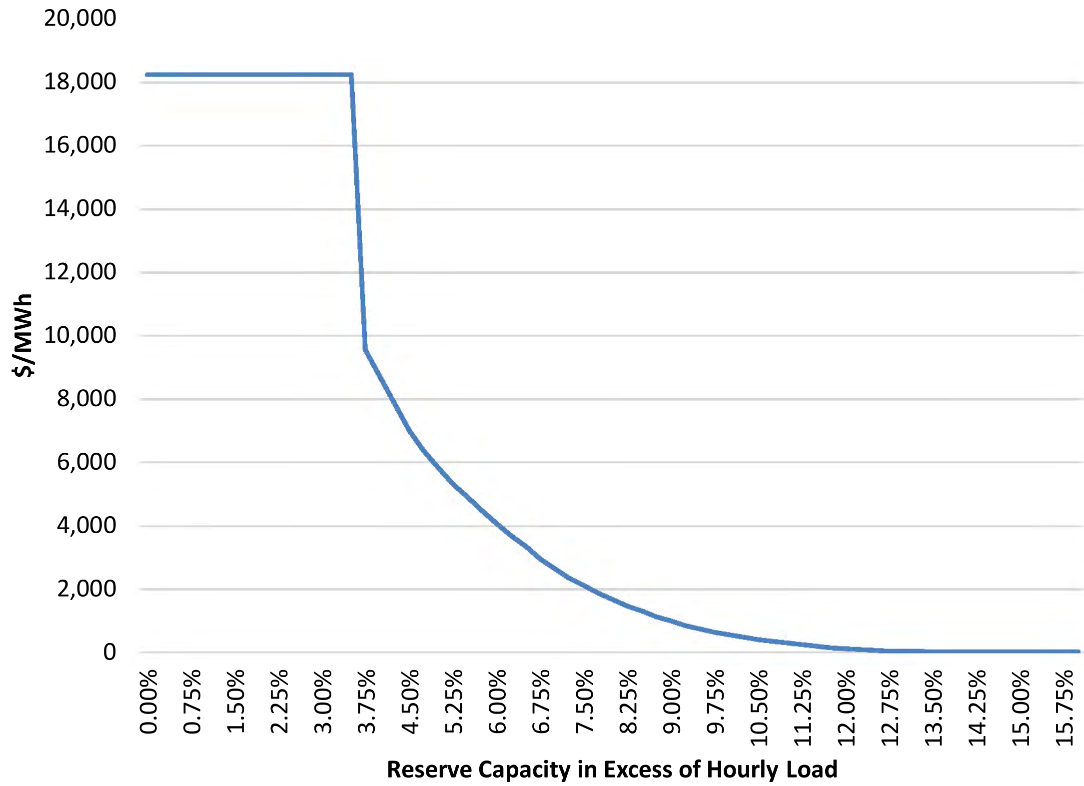
Reserve Margin = Total Supply/Peak Demand Forecast – 1

Total supply includes the Companies' generating resources and interruptible contracts. The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast. While the Companies are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.

4.10 Scarcity Pricing

As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply. Figure 6 plots the scarcity pricing assumptions in SERVM. The scarcity price is a function of reserve capacity in a given hour and is added to the marginal cost of supply to determine the price of purchased power. The Companies' assumed spinning reserve requirement (251 MW) is approximately 3.5% of the forecasted summer peak demand in 2021 (6,350 MW). At reserve capacities less than 3.5% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($18,250/MWh; see Section 4.7). The remainder of the curve is estimated based on market purchase data.

Figure 6: Scarcity Price Curve



The scarcity price impacts reliability and generation production costs only when generation reserves become scarce and market power is available. In ELDCM, the scarcity price is specified as a single value and is approximately $55/MWh. Because the scarcity price is difficult to specify, the analysis considered scarcity price sensitivities.

4.11 Summary of Scenarios

Reliability costs and loss-of-load events occur when loads are high or when supply is limited. To properly capture the cost of high-impact, low-probability events, the Companies evaluate thousands of scenarios that encompass a wide range of weather, load, and unit availability scenarios.

5 Analysis Results

5.1 Economic Reserve Margin and 1-in-10 LOLE Guideline

The Companies' forecasted reserve margin in 2021 is 23.5 percent in the base energy requirements forecast. Consistent with the methodology used in the 2014 IRP reserve margin analysis, the Companies estimated the sum of (a) annual capacity costs and (b) annual reliability and generation production costs over reserve margins ranging from 13 percent to 26 percent to identify the optimal generation mix for customers. To evaluate operating at lower reserve margins with less reliability, the Companies evaluated the retirement of its existing baseload and peaking resources. To determine if adding resources would cost-effectively improve reliability, the Companies evaluated the addition of new SCCT capacity. The generation portfolios evaluated in this analysis are described in Table 12. As discussed previously, the DCP and small-frame SCCTs are always assumed to be retired before other resources.

Table 12: Generation Portfolios Considered in Reserve Margin Analysis

Generation Portfolio	Portfolio Abbreviation	Reserve Margin
Add 140 MW of SCCT capacity to Existing portfolio	Add SCCT2	25.7%
Add 70 MW of SCCT capacity to Existing portfolio	Add SCCT1	24.6%
Existing (includes retirements of Brown 1, Brown 2, and Zorn 1)	Existing	23.5%
Retire DCP	Ret DCP	21.7%
Retire DCP, small-frame SCCTs	Ret DCP_SF	20.6%
Retire DCP, small-frame SCCTs, Brown 8	Ret B8*	18.7%
Retire DCP, small-frame SCCTS, Brown 8-9	Ret B8-9*	16.9%
Retire DCP, small-frame SCCTS, Brown 8-10	Ret B8-10*	15.0%
Retire DCP, small-frame SCCTS, Brown 8-11	Ret B8-11*	13.1%
Retire DCP, small-frame SCCTS, Brown 3	Ret B3*	14.2%

*Portfolio also includes retirement of DCP and small-frame SCCTs.

LOLE as well as reliability and generation production costs were evaluated in SERVM and ELDCM for each generation portfolio in Table 12 over 45 weather year scenarios and hundreds of unit availability scenarios. Table 13 contains for each portfolio the average LOLE from ELDCM as well as the annual sum of (a) capacity costs and (b) reliability and generation production costs ("total cost"). The same results from SERVM are summarized in Table 14. Portfolios with LOLE greater than five (i.e., five times the 1-in-10 LOLE physical reliability guideline) are highlighted in gray. These portfolios are not considered viable based on their poor reliability. Capacity costs for each generation portfolio are presented as the difference between the portfolio's capacity cost and the capacity cost for the Ret B3* portfolio. Total costs are estimated based on average ("Avg") reliability and generation production costs as well as the 85th and 90th percentiles ("%-ile") of the reliability and generation production cost distribution.

Table 13: Reserve Margin Analysis Results (ELDC Model, 2021 Dollars)

Generation Portfolio	2021 Reserve Margin	LOLE	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year) [B] Avg	[C] 85th %-ile	[D] 90th %-ile	Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year) [A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	25.7%	0.9	55.7	765	781	790	821	837	846
Add SCCT1	24.6%	1.2	47.1	766	782	791	813	829	838
Existing	23.5%	1.6	38.5	767	783	793	805	821	831
Ret DCP	21.7%	1.7	36.1	767	783	793	803	819	829
Ret DCP_SF	20.6%	2.0	35.9	768	783	794	803	819	830
Ret B8*	18.7%	2.9	34.4	770	789	799	805	824	833
Ret B8-9*	16.9%	4.3	33.0	775	799	806	808	832	839
Ret B8-10*	15.0%	6.3	31.6	781	812	822	813	844	854
Ret B8-11*	13.1%	9.0	30.2	790	829	843	820	859	873
Ret B3*	14.2%	7.4	0.0	784	817	832	784	817	832

*Portfolio also include retirement of DCP and small-frame SCCTs.

Table 14: Reserve Margin Analysis Results (SERVM, 2021 Dollars)

Generation Portfolio	2021 Reserve Margin	LOLE	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year) [B] Avg	[C] 85th %-ile	[D] 90th %-ile	Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year) [A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	25.7%	0.7	55.7	771	790	796	827	846	852
Add SCCT1	24.6%	1.0	47.1	771	793	797	818	840	844
Existing	23.5%	1.4	38.5	771	789	798	809	827	836
Ret DCP	21.7%	1.5	36.1	771	790	800	807	826	836
Ret DCP_SF	20.6%	1.8	35.9	772	792	801	808	828	837
Ret B8*	18.7%	2.6	34.4	773	796	805	807	831	839
Ret B8-9*	16.9%	3.8	33.0	775	808	814	808	841	847
Ret B8-10*	15.0%	5.8	31.6	780	815	819	812	847	850
Ret B8-11*	13.1%	8.5	30.2	788	833	844	819	863	874
Ret B3*	14.2%	8.3	0.0	791	837	843	791	837	843

*Portfolio also include retirement of DCP and small-frame SCCTs.

The results from ELDCM and SERVM are entirely consistent. The ranking of portfolios based on LOLE is the same in both models. Based on ELDCM, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is between 24.6 percent and 25.7 percent. Based on SERVM, this guideline is met with a 24.6 percent reserve margin. Considering the portfolios with LOLE less than five, when reliability and generation production costs are evaluated based on the average, 85^{th} percentile, or 90^{th} percentile of the distribution, the Existing and Ret DCP portfolios have the lowest total cost.

Beginning in 2019, the Companies will operate the Demand Conservation Programs in "maintenance" mode, allowing new participants to enroll in the program only to the extent existing devices are available to deploy. In addition, the Companies will reduce the annual incentive to $5 and pay participating customers only in years in which a Load Control Event is called. This analysis assumes customer participation will decline by almost 30 percent by 2021 as a result of these changes, but any actual change in customer participation is uncertain.

Additionally, the Companies face other uncertainties that impact resource planning decisions:

- Three of the Companies' coal units are not retrofitted with selective catalytic reduction ("SCR") so future changes to National Ambient Air Quality Standards may require one or more of the following actions in the next three to seven years: investment to further reduce emissions of nitrogen oxides ("NO_x"), changes in plant operations during ozone season, unit retirements, and acquisition of new generation.
- The U.S. Environmental Protection Agency ("EPA") recently proposed the Affordable Clean Energy Rule ("ACE Rule") which would establish guidelines for states to regulate carbon dioxide ("CO_2") emissions from existing fossil fuel-based electric generating units.[23] At a minimum, due to the regulatory timeline, fleet-specific and unit-specific planning for the ACE Rule is uncertain for the next two to four years.
- Lastly, as discussed in Section 5.(3) of Volume I, upside and downside uncertainty exists in the Companies' energy requirements forecast.

Given these uncertainties and the small differences in total costs between the Existing and Retire DCP portfolios, the Companies are not proposing to discontinue the DCP at this time. Instead, they will continue to the monitor participation in the DCP program and other regulatory and load developments to more holistically consider potentially broader changes to their generation mix in the future.

Consistent with the 2014 IRP reserve margin analysis, the Companies estimated total costs based on the 85th and 90th percentiles of the reliability and generation production cost distribution to consider the potential volatility in total costs for customers. For example, compared to the Existing portfolio and considering the results from both models, average annual reliability and generation production costs for the Ret B3* portfolio are $17 million to $20 million higher, but the Companies would expect these costs to be $39 million to $45 million higher once in ten years (90th percentile of distribution). With Brown 3 in the generation portfolio, the portfolio is far more reliable and reliability and generation production costs are significantly less volatile.

[23] EPA is proposing to exempt SCCT and NGCC units from the ACE Rule, subject to public comments.

5.2 Target Reserve Margin Range

The target reserve margin range established in the 2014 IRP Reserve Margin Analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline. Based on the Companies' current load forecast and resource mix, the reserve margin required to meet the 1-in-10 physical reliability guideline is approximately 25 percent (see Table 13 and Table 14). This increase is explained primarily by changes in the load forecast, which – consistent with recent history – assumes greater variability in winter peak demands (see Figure 5). The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015). The increased variability in winter peak demands is primarily the result of increasing penetrations of electric heating in the Companies' service territories.

For the minimum of the target reserve margin range, the Companies estimated the change in load that would require the addition of generation resources. Specifically, the Companies estimated the load increase that would cause the Add SCCT1 portfolio to be less costly than the Existing portfolio. The reserve margin associated with this increase is the minimum of the reserve margin range. Below this range, the Companies should seek to acquire additional resources to avoid reliability falling to levels that would likely be unacceptable to customers.

Because significant near-term load increases are most likely to be the result of the addition of one or more large industrial customers, the analysis evaluated the addition of large, high load factor loads.[24] The results of this analysis from ELDCM and SERVM are summarized in Table 15 and Table 16, respectively. Consistent with the 2014 IRP reserve margin analysis, this analysis is focused on total costs that are estimated based on the 85th and 90th percentiles of the reliability and generation production cost distribution for the purpose of reducing volatility for customers. With no change in the load, total costs for the Existing and Add SCCT1 portfolios are the same as in Table 13 and Table 14. Based on ELDCM and assuming all other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. The results from SERVM are very similar.

[24] Not all industrial loads have high load factors. In practice, significant load changes would have to be evaluated on a case-by-case basis to ensure reliable supply.

Table 15: Minimum of Target Reserve Margin Range (ELDC Model)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	821	829	8	831	838	7
50	22.5%	833	841	8	844	851	7
100	21.6%	845	853	7	857	864	6
150	20.6%	859	865	6	871	876	6
200	19.7%	874	877	4	885	890	5
250	18.8%	890	892	2	899	903	4
300	17.9%	907	908	1	914	918	3
350	17.0%	925	925	(1)	931	933	2
400	16.2%	943	942	(1)	949	949	0

Table 16: Minimum of Target Reserve Margin Range (SERVM)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	827	840	13	836	844	8
50	22.5%	840	847	7	851	855	4
100	21.6%	852	863	11	864	869	4
150	20.6%	866	875	8	879	882	3
200	19.7%	883	886	4	896	897	1
250	18.8%	900	899	0	913	913	0
300	17.9%	914	918	4	925	930	6
350	17.0%	932	934	2	947	945	(3)
400	16.2%	955	950	(5)	964	963	(1)

5.3 Sensitivity Analysis

The inputs to the reserve margin analysis are detailed in Section 4. Because several of these inputs are uncertain, the Companies evaluated several sensitivities to the base case inputs. Table 17 lists the least-cost generation portfolios for each sensitivity, considering portfolios with LOLE less than five. As demonstrated in Section 5.1, the total cost of the Retire DCP portfolio is slightly lower than the total cost of the Existing portfolio in the base case scenario. The Companies used ELDCM to evaluate sensitivities to the cost of unserved energy, scarcity prices, EFOR, and ATC.

Table 17: Sensitivity Analysis (Least-Cost Generation Portfolio)

Case	85th Percentile	90th Percentile
Base Case	Ret DCP	Ret DCP
Cost of Unserved Energy		
25% Higher Cost of Unserved Energy ($22,800/MWh)	Ret DCP	Ret DCP
25% Lower Cost of Unserved Energy ($13,700/MWh)	Ret DCP	Ret DCP
Scarcity Prices		
25% Higher Scarcity Prices	Ret DCP	Ret DCP
25% Lower Scarcity Prices	Ret DCP	Ret DCP
Unit Availability		
Increase EFOR by 1.5 Points	Existing	Ret DCP
Decrease EFOR by 1.0 Points	Ret DCP	Ret DCP
Available Transmission Capacity		
No Access to Neighboring Markets	Ret DCP	Existing
High ATC (1,000 MW of ATC During Peak Hours)	Ret DCP	Ret DCP

5.4 Final Recommendation

All other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. Furthermore, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is approximately 25 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

6 Appendix A: Stay-Open Cost Example

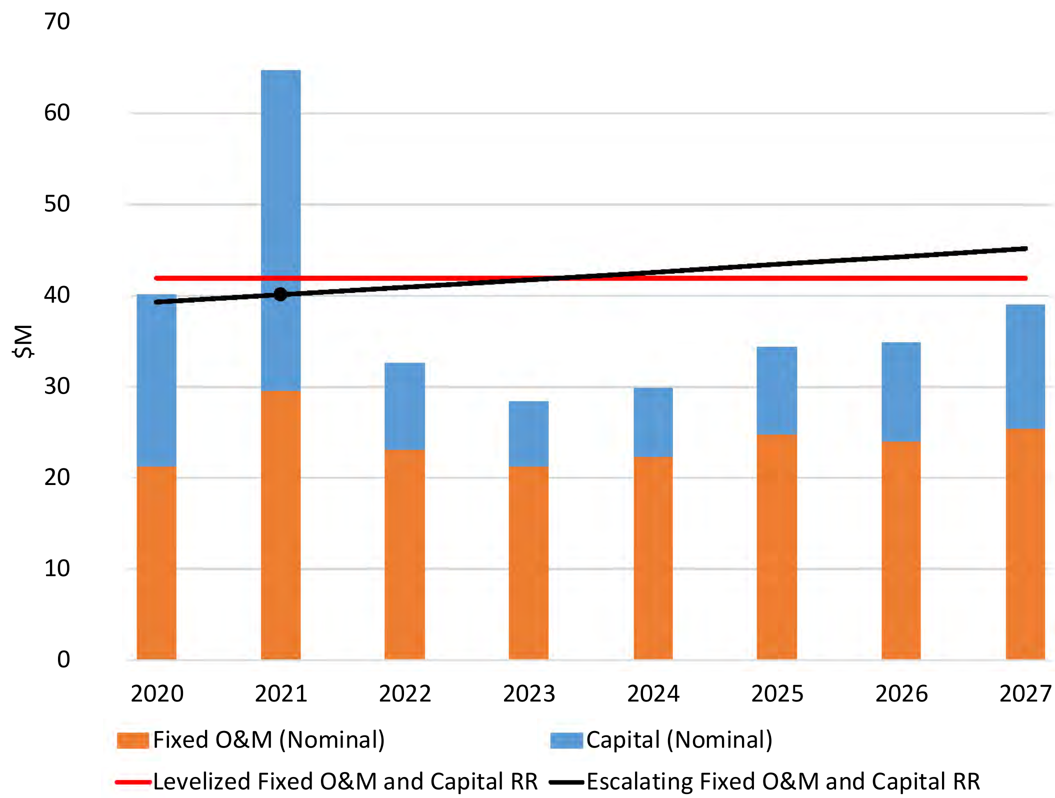
Table 18 contains capital and fixed O&M expenses for Ghent 1 over a typical 8-year maintenance cycle. With the exception of 2021 when the unit is scheduled for a turbine overhaul, fixed O&M is fairly consistent; several components of fixed O&M are assumed to grow at constant escalation rates. Capital costs are also highest in 2021 and more consistent in other years.

Table 18: Ghent 1 Capital and Fixed O&M (Nominal $M)

	2020	2021	2022	2023	2024	2025	2026	2027
Capital	18.8	35.1	9.5	7.1	7.5	9.6	10.8	13.6
Fixed O&M	21.3	29.6	23.1	21.3	22.3	24.9	24.0	25.4

To compute a stay-open cost for each marginal unit in 2021 dollars, the Companies levelized each unit's capital and fixed O&M expenses over the unit's maintenance cycle and adjusted the levelized capital cost to reflect the cost's impact on annual revenue requirements. Then, they converted the levelized cost stream into an escalating stream over the same period such that the levelized and escalating streams have the same present value of revenue requirements. In the escalating stream, costs are assumed to escalate at two percent per year. Figure 7 plots the result of this process for Ghent 1. The levelized cost is $41.9 million. The escalating cost is $40.1 million in 2021 and increases from $39.3 million in 2020 to $45.2 million in 2027.

Figure 7: Ghent 1 Stay-Open Costs



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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**

In the Matter of:

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**

SUPPLEMENTAL REBUTTAL TESTIMONY OF
JOHN K. WOLFE
VICE PRESIDENT, ELECTRIC DISTRIBUTION
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: August 5, 2021

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. Please state your name, position and business address.

A. My name is John K. Wolfe. I am Vice President of Electric Distribution for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut assertions by intervenor witnesses Justin R. Barnes, James Owen, and Karl R. Rábago as they relate to avoided distribution capacity cost. In particular, I argue that Mr. Barnes's proposal to calculate avoided distribution capacity cost using embedded distribution cost is fundamentally flawed and invalid because it bears no rational relationship to potentially avoidable distribution costs. I further argue that the claimed values for avoided distribution cost contained in a meta-analysis cited by Messrs. Owen and Rábago bear no relationship of any kind to the Companies' potentially avoidable distribution costs and therefore cannot be used to formulate the compensation rate under Rider NMS-2. Also, I address and refute Mr. Owen's assertion that the Commission should consider "reduced congestion at stressed nodes and distribution points along the grid" as a net-metering benefit from a distribution perspective because it is impossible to know before the fact whether net metering capacity will serve to alleviate or exacerbate distribution congestion (if it has any measurable effect at all). Finally, I explain why the Commission should not consider voltage control to be an NMS-2 compensation component at this time, contrary to Mr. Rábago's position.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibit to my supplemental rebuttal testimony, as well as supporting workpapers being filed with my testimony:

Supplemental Rebuttal Exhibit JKW-1	Effects of Distributed Generation on Distribution and Transmission

II. MR. BARNES'S AVOIDED DISTRIBUTION COST APPROACH IS FUNDAMENTALLY FLAWED BECAUSE IT BEGINS WITH EMBEDDED COSTS, WHICH CANNOT BE AVOIDED

Q. Mr. Barnes has proposed an avoided distribution cost value and calculation methodology based on embedded distribution costs.[1] Do you agree with his approach?

A. No. As I stated in my supplemental testimony, the first and most fundamental tenet of an appropriate framework for determining avoided distribution capacity cost arising from net metering must be that it consider future investments, not embedded costs. There is no amount of net metering that can change investments already made, so an accurate framework will consider only future investments.

Mr. Barnes's approach violates this fundamental avoided cost tenet. Although he did not attempt to calculate avoided distribution cost in his testimony, he asserted that he would apply the same basic approach to avoided distribution cost that he did to avoided transmission cost. Mr. Barnes's avoided transmission cost calculation begins with "unit costs derived by dividing net demand-related cost of service by the associated class demand allocator for each Company in order to produce a $/kW amount."[2] In other words, Mr. Barnes would begin with the embedded cost of the

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[1] Barnes Supplemental Testimony at 11.
[2] *Id.*

existing distribution system on a $/kW basis. Mr. Seelye addresses other problems with Mr. Barnes's approach, but beginning with embedded cost, i.e., the cost of the distribution system already in place, which by definition cannot be avoided, is a fundamental flaw.

Moreover, embedded distribution cost is not a reasonable or rational proxy for potentially avoidable distribution cost for at least two reasons. First, the embedded cost of distribution facilities is not necessarily predictive of the cost of future distribution facilities. Second and more problematically, much future distribution cost simply cannot be avoided, particularly by necessarily distributed and aggregate-capacity-capped intermittent generation in a generally flat to declining load environment. There is a minimum, unavoidable level of distribution cost that will exist as long as distribution-level facilities are required to connect various points in the electric grid: distribution poles have a minimum level of cost beyond which there is no further decrease, and the same is true for insulators, conductors, transformers, and installation costs. Therefore, it is illogical and unrealistic to assume that all distribution cost is potentially avoidable, yet that is exactly what Mr. Barnes's approach does by beginning with the entirety of embedded distribution cost.

III. HAYIBO AND PEARCE META-ANALYSIS VALUES CANNOT BE USED FOR AVOIDED DISTRIBUTION COST BECAUSE THEY ARE NOT BASED ON THE COMPANIES' COSTS, AVOIDED OR OTHERWISE

Q. Messrs. Owen and Rábago have suggested that the Commission might import values from a meta-analysis by Hayibo and Pearce to establish NMS-2

compensation rate components under certain conditions.[3] Would importing such values be valid regarding the Companies' potentially avoidable distribution costs?

A. No. As the abstract of the Hayibo and Pearce meta-analysis accurately states, "VOS [Value of Solar] calculations are challenging and there is widespread disagreement in the literature on the methods and data needed."[4] This seems to be true: the avoided distribution capacity values the meta-analysis provides range from zero to over three cents per kWh.[5] Such a large variance demonstrates that the one cannot simply take a value from the meta-analysis and assume it has any relationship at all the Companies' actually avoidable distribution capacity costs.

But more importantly, to the best of my knowledge, there is no data in the Hayibo and Pearce meta-analysis cited by Messrs. Owen and Rábago that derives from or ties to the Companies' embedded or potentially avoidable distribution costs. Therefore, it would be arbitrary to import an avoided distribution cost value from the meta-analysis; rather, the Commission should choose a value for the avoided distribution cost component of NMS-2 compensation that derives from the Companies' potentially avoidable distribution costs. As I testified in my supplemental testimony and continue to believe today, the most appropriate value for that component would be zero because I do not believe net metering will allow the Companies to avoid any distribution cost over the current planning horizon.

I would also note that of the 8 substation transformers the Companies' placed in service from 2016 through 2020 due to load growth:

[3] Owen Supplemental Testimony at 9; Rábago Supplemental Testimony at 9-10.
[4] Joint Intervenors' Response to Companies' Supplemental DR No. 4, Attachment 4 at 1.
[5] *Id.* at 14-15.

- Two of the new transformers were placed on circuits with zero connected NMS customers;
- None of the new transformers have connected NMS nameplate capacity greater than 1% of the transformer rating; and
- The highest ratio of connected NMS resources to one of the new distribution substation transformers is 0.54%

None of these transformers were affected by connected net metering capacity. This again shows that one cannot simply take a value from a meta-analysis and assume it bears any rational relationship to the Companies' actual systems or avoidable costs; rather, the Companies' actual data and experience indicate there is little, if any, distribution capacity cost that NMS-2 customers' energy exports could help avoid during the Companies' current planning horizon.

Q. Have the Companies performed an analysis that further supports your position that avoided distribution capacity costs due to NMS-2 customers' net energy exports are likely to be zero, making use of Hayibo and Pearce values inappropriate?

A. Yes. Supplemental Rebuttal Exh. JKW-1 to my testimony is an analysis prepared under my supervision in response to the intervenors' supplemental testimony. The Companies prepared the analysis to determine to what extent, if any, a significant saturation of net metering in a new residential development would impact distribution and transmission investment. More specifically, the analysis assumed that installation of distributed generation would be known ahead of time and 20% of new residences in a new 500-residence development (i.e., 100 residences) would have 10 kW DC of rooftop solar capacity each (i.e., a total of approximately 1 MW DC), using an average load shape for an existing LG&E neighborhood and an existing KU neighborhood. The analysis assumes ideal solar production curves (e.g., no clouds), based on actual solar production from the Companies' Solar Share Program facility.

The analysis shows there is *no* distribution capacity cost the Companies could achieve in such a situation—even if they knew in advance there would be 1 MW of solar generation capacity in a neighborhood before the neighborhood existed.[6] In reality, this kind of ideal foreknowledge never exists, so the Companies must assume they will have to serve standard residential loads in new developments and subdivisions, and they learn only after a development is complete where and to what extent net metering capacity might locate. This further supports the Companies' view that net metering is likely to avoid little or no distribution capacity cost.

Also, as Ms. McFarland notes in her supplemental rebuttal testimony, the analysis shows that the load forecast provided to Transmission from Distribution, which is used to determine the amount of transmission capacity required to serve the neighborhood in the study, is not expected to be reduced as a result from the installation of such a large amount of distributed solar generation.

[6] Note that the analysis actually *overstates* the MW load reduction provided by the net energy supplied by the hypothetical net metering customers. This is true because it includes the full impact of the net metering customers' energy—including energy they consume—not only net energy, which is the relevant quantity for NMS-2 purposes.

IV. THE COMMISSION SHOULD ASSIGN A VALUE OF ZERO AVOIDED DISTRIBUTION CONGESTION COSTS BECAUSE IT IS IMPOSSIBLE TO KNOW WHETHER NET METERING WILL IMPROVE OR WORSEN CONGESTION

Q. Mr. Owen's supplemental testimony asserts that the Commission should consider "reduced congestion at stressed nodes and distribution points along the grid."[7] Do you agree?

A. I agree it is reasonable to consider congestion impacts, but I do not agree with Mr. Owen's apparent assumption that net metering can have only beneficial congestion impacts. As I noted in the analytical framework I proposed in my supplemental testimony regarding avoided distribution cost, the location of energy exports that affect distribution system components affects either the cost or benefit of those exports. One cannot simply assume that all exports are beneficial: if an export is significant enough to have an appreciable effect on distribution components, it might be beneficial if it relieves distribution congestion, or it could exacerbate existing congestion. It appears Mr. Owen would have the Commission assume only upside in this regard, notwithstanding there is no evidence to support such an assumption.

Also, it would take a significant amount of properly located net metering capacity producing energy at the right times to have a substantial effect on distribution congestion. The likelihood of this occurring is remote due to the necessarily distributed nature of net metering and the statutory cap on net metering capacity; as I demonstrated in my supplemental testimony, the net metering capacity in place today is highly dispersed and has created no known distribution system cost savings. In addition, when production to the grid from net metering resources might be most helpful to address

[7] Owen Supplemental Testimony at 3 and 7.

distribution constraints is often when net metering customers are drawing on their own energy production and therefore exporting relatively little energy to the grid, or they are producing little to no energy at all in the case of winter peaks on the KU system. Moreover, the Companies do not currently plan or choose (or have the right to plan or choose) where net metering customers will locate, what kinds and sizes of facilities they will choose, or when the conditions will be right for actual energy production to occur.

Therefore, I believe net metering will have no measurable impact on distribution congestion during the current planning horizon, and it is impossible to know *ex ante* whether any impact it might have will be beneficial or harmful. Under such circumstances, though it is appropriate for the Commission to consider net metering's impact on distribution congestion, the most appropriate value to assign to it is zero.

V. THE COMMISSION SHOULD NOT ASSIGN A VALUE FOR VOLTAGE CONTROL BECAUSE THE COMPANIES DO NOT HAVE THE MEANS TO USE NET METERING FACILITIES FOR VOLTAGE CONTROL

Q. Mr. Rábago's supplemental testimony asserts that the Commission should consider "Voltage Control" in its benefit-cost framework.[8] Do you agree?

A. It would be reasonable to consider voltage control benefits associated with net metering under two conditions, neither of which is met in these proceedings. First, the Companies would need to have some means of controlling the output of net metering facilities, which they do not currently have and do not plan to have in the current planning horizon. Second, the Companies would need either a tariff requirement or

[8] Rábago Supplemental Testimony at 4-5.

owner permission to allow them to control the output of net metering facilities, which again the Companies do not have and do not plan to have in the current planning horizon. Moreover, if the Companies were required to obtain owner permission to control net metering facility output to assist in voltage control, it is possible the Companies would need to pay owners for the right to have such control, in which case including voltage control compensation in the NMS-2 rate would double-compensate customers who gave control to the Companies while compensating other NMS-2 customers for a service they refused to provide.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of August 2021.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

PPL companies

Effects of Distributed Generation on Distribution & Transmission

Problem Statement

LG&E and KU (Companies) wish to determine the effects that Distributed Generation (DG) has when designing distribution and transmission infrastructure for new construction. The Companies would like to know if cost savings are possible during engineering and construction if it is known that DG is installed on 20% of the new customers up front during the design process.

Approach

Two neighborhoods were chosen for the study due to the likelihood of installing DG. These include the Norton Commons community in Louisville (LG&E) and the Rocky Creek Reserve community in Lexington (KU). Modeling was performed to show the effects of DG on net load for an average customer in each of the two areas, a customer with natural gas service in the LG&E service area and a customer without gas service in the KU service area. These results were used to determine if any design or construction changes would be necessary knowing that a subset of homes would have DG. Additionally, the results from the distribution study were then modeled for a new 500 home development/expansion to determine any impacts on the transmission system. Finally, the Companies gathered costs for typical new neighborhood construction or expansion using traditional design practices. Using the results from the modeling exercise, the Companies predicted any changes in construction costs resulting from DG installation.

DG Modeling Effort

15-minute interval load data was collected from customers participating in the AMI smart meter opt-in program over a 2-year span in 2019 and 2020. For the LG&E case, meter data was collected from 47 residential meters on the WO1184 circuit, which feeds the Norton Commons community. Similarly, for the KU case, meter data was collected from 21 residential meters on the 777-0431 circuit, which feeds the Rocky Creek Reserve community. This data was then combined to determine average seasonal load profiles for a typical customer in each of the Companies' service areas.

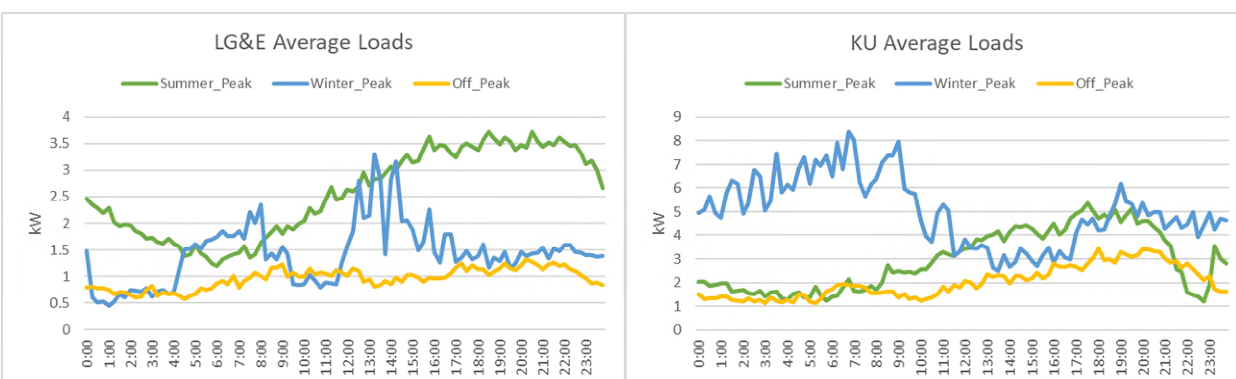

Figure 1 – (Left) Average load profiles calculated from AMI opt-in data on WO1184 in the LG&E service area without DG. (Right) Average load profiles calculated from AMI opt-in data on 777-0431 in the KU service area without DG.

Next, solar production data was gathered from the Companies' Simpsonville Solar Share facility for various seasons (summer, winter, and off-peak; see Figure 2 below). Multiple seasons were chosen due to the variation in solar production throughout the year. Additionally, production profiles favorable to solar were chosen (e.g., essentially no cloud cover was assumed in the summer and winter profiles). This production was scaled to various size arrays (5 kW, 10 kW, and 15 kW) to represent the typical array sizes seen on residential customer interconnections. An example of the 10 kW array production data is shown in the following figure. Analysis was performed using NREL's PVWatts calculator to determine the average annual energy production from various sized arrays.[1] Using this analysis, it was determined that a 10 kW solar array would produce enough energy annually for the average customer in LG&E to consume net zero energy. Similarly, a 16 kW array would result in net zero energy for a KU customer.

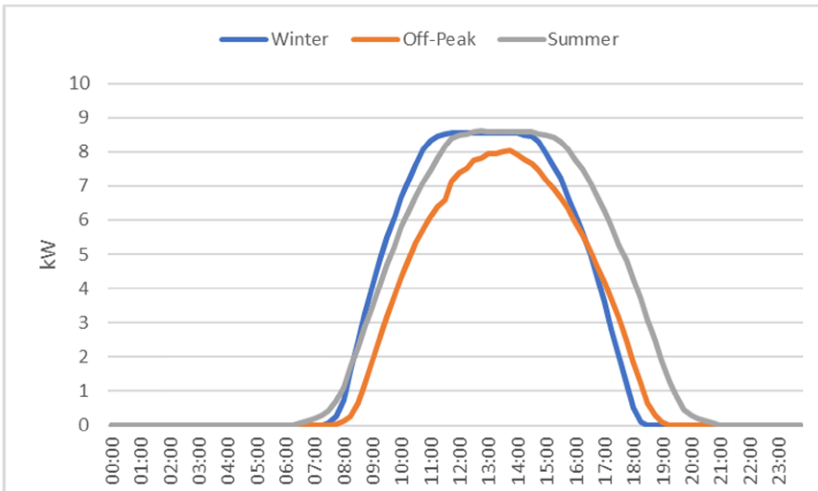

Figure 2 - Solar production profiles used during the analysis. All data was captured from the LG&E and KU Simpsonville Solar Share facility.[2] Note that only the 10 kW array size profiles are shown here and a 1.2 DC to AC ratio was assumed.

The solar profiles in Figure 2 were added to the average customer load shapes in Figure 1 to determine the net load on a typical distribution service transformer serving a single customer. The results of this analysis are shown in Figure 3. Note that without solar, the service transformer would be sized to serve approximately 5 kVA of peak load for an LG&E customer and approximately 10 kVA of peak load for a KU customer. Once the solar array is added to the net load shape, the service transformer must now be upsized to handle increased power flows in cases where the excess solar generation exceeds the average peak load. This could result in increased costs during design and construction of the utility service.

In typical designs, a service transformer serves multiple customers under the assumption that secondary length does not create negative impacts to voltage loss. In instances where multiple customers are served from a single service transformer, it is of importance to note that transformer upsizing would only be required when multiple customers on that transformer install solar PV. In cases where only a single customer on a given service transformer installs solar PV, the excess energy would most likely be

[1] https://pvwatts.nrel.gov/pvwatts.php
[2] https://lge-ku.com/solar-share

PPL companies

consumed by the coincident loads from other customers. Therefore, the locational analysis of solar PV is critical to ensure that service transformers are not overloaded.

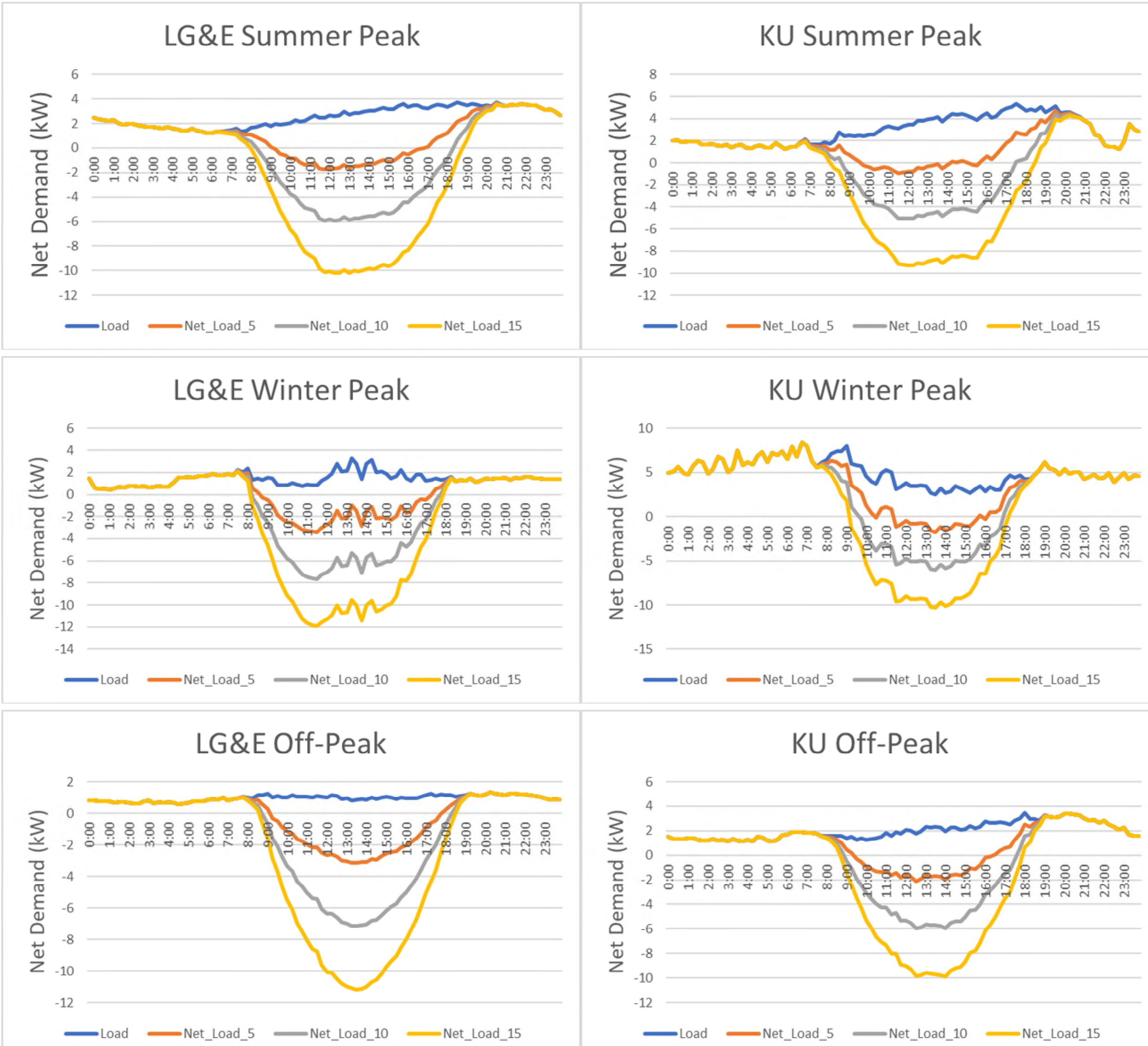

Figure 3 - (Left) Summer, Winter, and Off-peak load profiles with solar for an average LG&E residential customer. (Right) Summer, Winter, and Off-peak load profiles with solar for an average KU residential customer.

Additional modeling was performed at the substation level to determine any resultant effects on the transmission system. Two cases were studied: a 500-home development with no solar added, and a 500-home development with 20% of those new homes (100) having 10 kW rooftop solar arrays. Note that this assumption of nearly 1 MW of DG interconnection in a concentrated area is highly favorable to net metering solar deployment, especially when considering the 15% capacity limit outlined in the Kentucky

LG&E KU
PPL companies

Public Service Commission's current Net Metering Interconnection Guidelines for Level 1 installations.[3] If each hypothetical 500-residence development were treated as a standalone line section due to the need for a sectionalizing recloser, the LG&E development would have a net metering capacity of 45% or more of the hypothetical annual peak load, and the KU development would have a net metering capacity of 20% or more of the hypothetical annual peak load on each respective line section. Both would be well in excess of the 15% limit for Level 1 interconnections. Additionally, the highest concentration of net metering generation behind a single substation transformer as of August 2, 2021, is only 398 kW for LG&E and 362 kW for KU, both of which are significantly less than 1 MW.

In LG&E the net impact of the 500-home development at the Worthington substation was modeled, and for KU the net impact at the Newtown substation (777) was modeled. The resultant net loads at each transformer, for each case and season, are shown in the following figure. The addition of solar does reduce the summer peak slightly but has little to no effect on the non-summer peaks, which typically occur outside of the hours that solar produces.

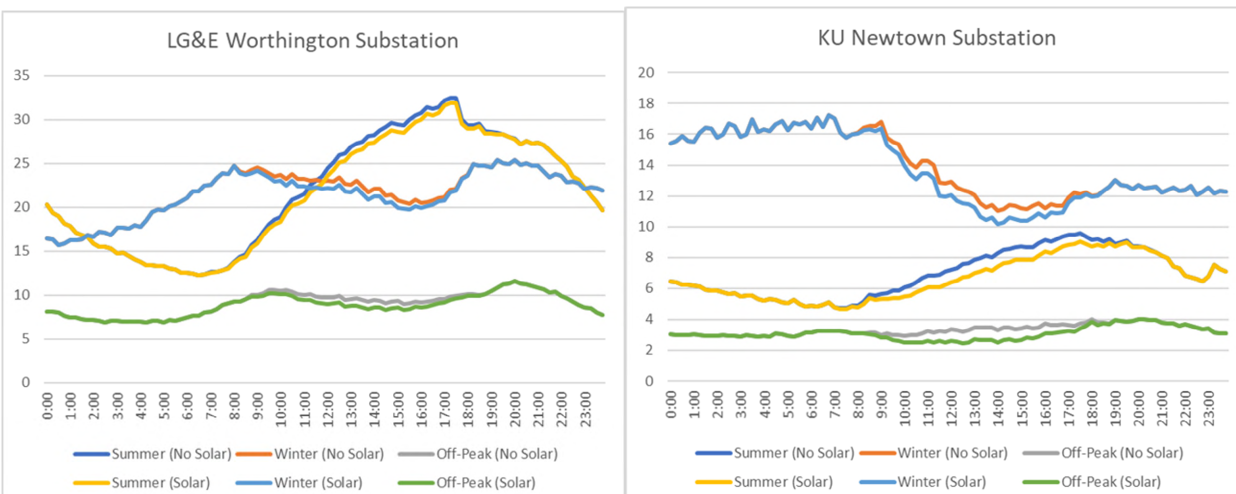

Figure 4 - Impact of 500 home development at distribution substation. (Left) LG&E (Right) KU

The peak load savings from distributed generation for each seasonal profile were then calculated and are summarized in Table 1. Since the net effects of solar generation on system peak are less than 1 MW for LG&E (summer) and 0 MW for KU (winter), the MW savings would be rounded to 0 MW for planning purposes. Therefore, distribution's input in modeling data provided to the Transmission Planning Assessment would be a 0 MW reduction as a result of DG. This is due primarily to the non-coincidence of solar production with the actual load peaks on LG&E and KU circuits.

[3] Under the Kentucky Public Service Commission's current Net Metering Interconnection Guidelines, "For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices."

PPL companies

Table 1 - Seasonal load savings at peak resulting from the addition of DG.

	Load Savings w/Solar (MW)		
	Summer	Winter	Off-Peak
LG&E	0.582301	0	0
KU	0.529001	0	0.184921

Construction Cost Analysis

Costs were estimated for a typical 60 home development using joint-trench design being added to an existing substation and distribution circuit. These costs were then extrapolated to a 500 home development and are summarized in Table 2. Note that KU does not show any gas costs. Distribution Engineering predicts that the only cost changes due to the addition of solar would be an increase in service transformer costs. This increase is due to the larger transformers needed to support DG injection when multiple homes with solar are connected to a single service transformer. It is estimated that this cost increase would be minimal, around $10k-$11k in total, and is a fraction of the total cost shown in Table 2.

Table 2 - Summary of costs for a 500-home development being added to an existing circuit. The addition of DER is not assumed in this estimate.

Line Item	LG&E				KU			
	Material	Labor	Overhead	Total	Material	Labor	Overhead	Total
Gas Pipeline	$130,675.00	$250,016.67	$ 46,883.33	$ 427,575.00	N/A	N/A	N/A	N/A
Wire and Cable	$239,825.00	$281,083.33	$ 65,325.00	$ 586,233.33	$239,825.00	$281,083.33	$ 65,325.00	$ 586,233.33
Transformers	$268,466.67	$ 36,100.00	$ 9,008.33	$ 313,575.00	$268,466.67	$ 36,100.00	$ 9,008.33	$ 313,575.00
Conduit / Misc.	$350,000.00	$598,633.33	$117,225.00	$1,065,858.33	$350,000.00	$598,633.33	$117,225.00	$1,065,858.33
Sectionalizing Recloser	$ 40,000.00	$ 10,000.00	$ 1,500.00	$ 51,500.00	$ 40,000.00	$ 10,000.00	$ 1,500.00	$ 51,500.00
Total:				$2,444,741.66				$2,017,166.66

Conclusions

In conclusion, the Companies performed modeling using AMI data from two representative circuits. This data, combined with solar production data, was used to determine the net impact on the distribution and transmission systems. Distribution impacts are limited to the possibility of needing larger service transformers to handle excess solar generation. No savings are possible on the distribution system due to adequate capacity already being present. Distribution services provided by the DG are possible, but this is not feasible until a DERMS is implemented, and independent production meters are installed to monitor asset performance. Also, any benefits from distribution services would be localized near the DG interconnection and would provide minimal impact at the distribution substation. Additionally, since 20% penetration of solar PV on a new 500 home development would have little impact on the peak demand for each circuit studied, due to non-coincidence between solar production and load, the net impact on the transmission system would be negligible. Therefore, transmission cannot account for and benefit from the DG when planning or operating the transmission system.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)	
KENTUCKY UTILITIES COMPANY FOR AN	)	**CASE NO. 2020-00349**
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	)	

In the Matter of:

ELECTRONIC APPLICATION OF	)	
LOUISVILLE GAS AND ELECTRIC	)	**CASE NO. 2020-00350**
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	)	

SUPPLEMENTAL REBUTTAL TESTIMONY OF BETH MCFARLAND VICE PRESIDENT - TRANSMISSION KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: August 5, 2021

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. Please state your name, position, and business address.

A. My name is Beth McFarland. I am Vice President of Transmission for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut assertions by intervenor witnesses Justin R. Barnes, James Owen, and Karl R. Rábago as they relate to avoided transmission capacity cost. In particular, I argue that Mr. Barnes's proposal to calculate avoided transmission capacity cost using embedded transmission cost is fundamentally flawed and invalid because it bears no rational relationship to potentially avoidable transmission costs. I further argue that the claimed values for avoided transmission cost contained in a meta-analysis cited by Messrs. Owen and Rábago bear no direct relationship to the Companies' potentially avoidable transmission costs and therefore cannot be used to formulate the compensation rate under Rider NMS-2. Finally, I address and refute Mr. Owen's assertion that the Commission should consider "reduced congestion at stressed nodes and distribution points along the grid" as a net-metering benefit from a transmission perspective because the statutory cap on net metering capacity and the limit on such capacity per distribution feeder make any potential transmission congestion relief improbable and because it is impossible to know before the fact whether net metering capacity will serve to alleviate or exacerbate transmission congestion (if it has any measurable effect at all).

II. MR. BARNES'S AVOIDED TRANSMISSION COST APPROACH IS FUNDAMENTALLY FLAWED BECAUSE IT BEGINS WITH EMBEDDED COSTS, WHICH CANNOT BE AVOIDED

Q. Mr. Barnes has proposed an avoided transmission cost value and calculation methodology based on embedded transmission costs.[1] Do you agree with his approach?

A. No. As I stated in my supplemental testimony, the first and most fundamental tenet of an appropriate framework for determining avoided transmission capacity cost arising from net metering must be that it consider future investments, not embedded costs. There is no amount of net metering that can change investments already made, so an accurate framework will consider only future investments.

Mr. Barnes's approach violates this fundamental avoided cost tenet. His calculation begins with "unit costs derived by dividing net demand-related cost of service by the associated class demand allocator for each Company in order to produce a $/kW amount."[2] In other words, Mr. Barnes begins with the embedded cost of the existing transmission system on a $/kW basis. He then scales that value by the percentage of solar capacity he believes will be available at system peak and divides it by the kWh of production he expects a kW of net metering solar capacity will produce annually to arrive at his proposed avoided transmission capacity component in $/kWh. Mr. Seelye addresses other problems with this approach, but the most fundamental problem is that it begins with embedded cost, i.e., the cost of the transmission system already in place, which by definition cannot be avoided.

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[1] Barnes Supplemental Testimony at 10.
[2] *Id.*

Moreover, embedded transmission cost is not a reasonable or rational proxy for potentially avoidable transmission cost for at least two reasons. First, the embedded cost of transmission facilities is not necessarily predictive of the cost of future transmission facilities. Second and more problematically, much future transmission cost simply cannot be avoided, particularly by necessarily distributed and aggregate-capacity-capped intermittent generation in a generally flat to declining load environment. There is a minimum, unavoidable level of transmission cost that will exist as long as transmission-level facilities are required to connect various points in the electric grid: transmission poles and towers have a minimum level of cost beyond which there is no further decrease, and the same is true for insulators, conductors, static wires, transformers, switches, and associated installation costs. Therefore, it is illogical and unrealistic to assume that all transmission cost is potentially avoidable, yet that is exactly what Mr. Barnes's approach does by beginning with the entirety of embedded transmission cost.

III. HAYIBO AND PEARCE META-ANALYSIS VALUES CANNOT BE USED FOR AVOIDED TRANSMISSION COST BECAUSE THEY ARE NOT BASED ON THE COMPANIES' COSTS, AVOIDED OR OTHERWISE

Q. Messrs. Owen and Rábago have suggested that the Commission might import values from a meta-analysis by Hayibo and Pearce to establish NMS-2 compensation rate components under certain conditions.[3] Would importing such values be valid regarding the Companies' potentially avoidable transmission costs?

[3] Owen Supplemental Testimony at 9; Rábago Supplemental Testimony at 9-10.

A. No. As the abstract of the Hayibo and Pearce meta-analysis accurately states, "VOS [Value of Solar] calculations are challenging and there is widespread disagreement in the literature on the methods and data needed."[4] This seems to be true: the avoided transmission capacity values the meta-analysis provides range from less than one cent per kWh to over six cents per kWh.[5] Such a large variance demonstrates that one cannot simply take a value from the meta-analysis and assume it has any relationship at all to the Companies' actually avoidable transmission capacity costs.

Moreover, the meta-analysis states, "The parameter it [avoided transmission capacity cost] is the most sensitive to is the transmission capacity cost. Obviously, when the transmission is low cost in a location, the avoided cost associated will be low."[6] That is indeed obviously true, and it supports using the Companies' actual data to determine an avoided transmission capacity cost; as I noted in my supplemental testimony and Mr. Seelye addressed in his supplemental testimony, the Companies have limited marginal transmission cost in their current planning horizon, which further supports not simply taking a value from the Hayibo and Pearce meta-analysis and supposing it reflects the Companies' avoidable transmission capacity costs.

But most importantly, to the best of my knowledge, there is no data in the Hayibo and Pearce meta-analysis cited by Messrs. Owen and Rábago that derives from or ties to the Companies' embedded or potentially avoidable transmission costs. Notably, when asked if they were aware of any evidentiary link between the values in the meta-analysis and the Companies' avoidable costs of providing service to their

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[4] Joint Intervenors' Response to Companies' Supplemental DR No. 4, Attachment 4 at 1.
[5] *Id.* at 14-15.
[6] *Id.* at 8.

customers, neither Mr. Owen nor Mr. Rábago provided such a link.[7] Therefore, it would be arbitrary to import an avoided transmission cost value from the meta-analysis; rather, the Commission should choose a value for the avoided transmission cost component of NMS-2 compensation that derives from the Companies' potentially avoidable transmission costs. As I testified in my supplemental testimony and continue to believe today, the most appropriate value for that component would be zero because I do not believe net metering will allow the Companies to avoid any transmission cost over the current planning horizon.

Q. Have the Companies performed an analysis that further supports your position that avoided transmission capacity costs due to NMS-2 customers' net energy exports are likely to be zero, making use of Hayibo and Pearce values inappropriate?

A. Yes. Supplemental Rebuttal Exh. JKW-1 to John K. Wolfe's supplemental rebuttal testimony is an analysis the Companies performed in response to the intervenors' supplemental testimony to determine to what extent, if any, a significant saturation of net metering in a new residential development would impact distribution and transmission investment. More specifically, the analysis assumed that installation of distributed generation would be known ahead of time and 20% of new residences in a new 500-residence development (i.e., 100 residences) would have 10 kW DC of rooftop solar capacity each (i.e., a total of approximately 1 MW DC), using an average load shape for an existing LG&E neighborhood and an existing KU neighborhood. One part of the analysis showed the impact of each such new residential development's solar

[7] Joint Intervenors' Response to Companies' Supplemental DR Nos. 4 and 6.

production on the substation that would serve it would effectively round to zero at each substation's summer peak hour and actually be zero during the winter peak hour.[8] Therefore, the load forecast provided to Transmission from Distribution, which is used to determine the amount of transmission capacity required to serve the neighborhood in the study, is not expected to be reduced as a result from the installation of such a large amount of distributed solar generation. This is just additional evidence that net metering is likely to avoid little or no transmission capacity cost.

I would also note that this analysis helps avoid the problem inherent in a purely academic meta-analysis of like that of Hayibo and Pearce. The Companies do not serve abstractions; rather, we serve actual customers with real electrical requirements that we must meet every moment of every day, 24 hours a day, seven days a week, 365 days a year, no matter the season or weather, *and regardless of whether the sun is shining*. This is especially important in Kentucky where approximately 50% of electricity needs occur at night when the sun is not shining. The Companies take the obligation to serve very seriously; we do all we reasonably can to be prepared to serve at every minute of every day. That is why it is important to study actual load shapes, actual solar production (albeit with very generous assumptions for solar), and how they actually apply to real substation data.

[8] Note that the values shown in the "Load Savings w/ Solar" table on page 4 of the analysis actually *overstate* the MW load reduction provided by the net energy supplied by the hypothetical net metering customers. This is true because it includes the full impact of the net metering customers' energy—including energy they consume—not only net energy, which is the relevant quantity for NMS-2 purposes.

IV. THE COMMISSION SHOULD ASSIGN A VALUE OF ZERO AVOIDED TRANSMISSION CONGESTION COSTS BECAUSE IT IS IMPOSSIBLE TO KNOW WHETHER NET METERING WILL IMPROVE OR WORSEN CONGESTION

Q. Mr. Owen's supplemental testimony asserts that the Commission should consider "reduced congestion at stressed nodes and distribution points along the grid."[9] Do you agree?

A. I agree it is reasonable to consider congestion impacts, but I do not agree with Mr. Owen's apparent assumption that net metering can have only beneficial congestion impacts. As I noted in the analytical framework I proposed in my supplemental testimony regarding avoided transmission cost, the location of energy exports that affect transmission system components affects either the cost or benefit of those exports. One cannot simply assume that all exports are beneficial: if aggregated exports are significant enough to have an appreciable effect on transmission components, it might be beneficial if it relieves transmission congestion, or it could exacerbate existing congestion. It appears Mr. Owen would have the Commission assume only upside in this regard, notwithstanding there is no evidence to support such an assumption.

Also, it would take a significant amount of properly located net metering capacity producing energy at the right times to have a significant effect on transmission congestion. The likelihood of this occurring is remote due to the necessarily distributed nature of net metering and the statutory cap on net metering capacity. Moreover, the Companies do not plan or choose where net metering customers will locate, what kinds

[9] Owen Supplemental Testimony at 3 and 7.

and sizes of facilities they will choose, or when the conditions will be right for actual energy production to occur.

Therefore, I believe net metering will have no measurable impact on transmission congestion, and it is impossible to know *ex ante* whether any impact it might have will be beneficial or harmful. Under such circumstances, though it is appropriate for the Commission to consider net metering's impact on transmission congestion, the most appropriate value to assign to it is zero.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Elizabeth J. McFarland**, being duly sworn, deposes and says that she is Vice President, Transmission for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Beth McFarland
Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of August 2021.

Notary Public

Notary Public ID No. **603967**

My Commission Expires:

July 11, 2022