COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY AND LOUISVILLE GAS	**)**	
AND ELECTRIC COMPANY FOR CERTIFICATES	**)**	**CASE NO.**
OF PUBLIC CONVENIENCE AND NECESSITY	**)**	**2025-00045**
AND SITE COMPATIBILITY CERTIFICATES	**)**	

DIRECT TESTIMONY OF
CHARLES R. (CHUCK) SCHRAM
DIRECTOR, POWER SUPPLY
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 28, 2025

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INTRODUCTION

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

A. My name is Chuck Schram. I am the Director of Power Supply 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 2701 Eastpoint Parkway, Louisville, Kentucky 40223. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before this Commission numerous times, including in the Companies' most recent certificates of public convenience and necessity ("CPCN") application proceeding ("2022 CPCN-DSM Case").[1]

Q. What is the purpose of your direct testimony?

A. First, I provide an overview of the functions of the Power Supply team I lead. Second, I discuss the recent winter weather events and the performance of the Companies' generation resources and the Companies' gas pipeline service providers during the events. Third, I address the Companies' May 2024 request for proposals ("RFP") for renewable energy, provide an update on the solar purchase power agreements ("PPAs") previously executed by the Companies, and explain what the Companies have learned about building and operating battery energy storage systems ("BESS"). Fourth and finally, I discuss the natural gas supply and fuel security considerations for the two

[1] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Direct Testimony of Charles R. Schram (Dec. 15, 2022).

natural gas combined cycle ("NGCC") units for which the Companies are seeking certificates of public convenience and necessity ("CPCNs") in this proceeding.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring two exhibits:

Exhibit CRS-1	May 2024 RFP
Exhibit CRS-2	May 2024 RFP Responses

THE ROLE OF POWER SUPPLY

Q. Please describe your responsibilities as Director of Power Supply.

A. As Director of Power Supply, I am responsible for ensuring customers reliably receive service at the lowest reasonable cost year-round, around-the-clock, and in all weather, generation availability, and market conditions. Power Supply's responsibilities include:

- Weather forecast assimilation. Weather, particularly temperature, drives a large amount of demand and changes in demand on the Companies' resources. Therefore, although the Companies do not forecast weather per se, Power Supply gathers data from several third-party forecasters to assemble a forecast the Companies use in their short-term load forecasting.
- Short-term load forecasting. Whereas Tim A. Jones and his team are responsible for long-term load forecasts that inform the Companies' resource plans, Power Supply is responsible for creating short-term load forecasts that inform the Companies' unit commitments, dispatch decisions, and energy market activity (purchases or sales).

- Monitoring generation unit availability and making unit commitment decisions. To ensure reliable service at all times, Power Supply constantly monitors generation unit availability and status and commits units as needed to ensure they can be dispatched to meet customers' needs moment-to-moment at the lowest reasonable cost, i.e., the Companies always seek to commit and dispatch resources in economic merit order to the extent consistent with maintaining reliable service. As part of this responsibility, Power Supply regularly communicates with generating station personnel both to understand unit status but also to inform the plant operators concerning anticipated unit availability needs.
- Real-time dispatch. Power Supply's operations team performs the real-time generation dispatch function to reliably serve the Companies' customers at every moment. The Companies have experienced hourly winter load that varies up to 2,760 megawatts ("MW") in a day and hourly summer load that varies 3,220 MW in a day. Furthermore, intra-hour load can swing by several hundred megawatts over the course of an hour and more than 100 MW over a period of seconds, highlighting the importance of generation assets with ramping capabilities to meet these changes in demand. Generation dispatchers monitor all available resources' response abilities. This includes load control programs that must reliably reduce energy demand per design specifications.
- Energy trading. Power Supply staff monitor and participate in energy markets, including PJM, MISO, and SEEM, year-round and around-the-clock to maximize the value of the Companies' generation assets for customers' benefit

when market prices and customers' own energy needs allow for profitable off-system sales, as well as to acquire energy for customers' benefit when it is available at a lower price than the Companies' marginal cost of energy.

- Natural gas acquisition and procurement strategy, including pipeline transportation service and hedging activity and strategy. Power Supply purchases all of the natural gas to fuel the Companies' gas-fired generation units. The Companies hedge against gas price volatility, and therefore reduce customers' bill volatility, by purchasing a portion of the gas supply for the Cane Run 7 NGCC on a forward basis.

In addition to these ongoing responsibilities, I led negotiations for the Companies' first two solar PPAs executed in 2019 and 2021 and the four solar PPAs the Commission reviewed and approved in the Companies' 2022 CPCN-DSM Case.[2] I was also responsible for administering the Companies' tolling agreement for the Bluegrass Unit 3 combustion turbine from 2015 to 2019.

Power Supply's commercial responsibilities also include formulating and issuing electric energy and capacity RFPs, working with RFP respondents regarding their responses, and conducting negotiations with RFP respondents to arrive at appropriate commercial arrangements and contracts. In my role as Director of Power Supply, I am therefore quite familiar with and have personal knowledge of the Companies' most recent renewable energy RFP and the responses the Companies received.

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[2] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order at 179 (Ky. PSC Nov. 6, 2023).

THE PERFORMANCE OF THE COMPANIES' GENERATING FLEET DURING THE RECENT WINTER STORM AND POLAR VORTEX EVENTS

Q. Do you have any observations concerning the performance of the Companies' generating fleet and the performance of the gas pipelines that supply the Companies' gas-fired units during the recent winter storm and polar vortex events?

A. Yes. First, during the January 5-6, 2025 winter storm that deposited unusual, though not unprecedented, amounts of snow and ice across the Companies' Kentucky service territories, the Companies' coal- and gas-fired generation fleet had no notable issues and no gas pressure or other gas-related service issues to their generation units; the Companies' gas pipelines all performed well. Although electric demands were not abnormally high (because temperatures were not abnormally low), it was still noteworthy that the Companies' coal and gas fleet served customers well.

The second and much more challenging event from a power supply perspective was the polar vortex event that drove temperatures at the Louisville International Airport into the single digits beginning in the evening of January 21 and persisting through the mid-morning of January 22, with a low temperature of 4°F between about 4:00 a.m. and 7:00 a.m. on January 22.[3] Temperatures recorded in Lexington at the Blue Grass Airport followed a similar trajectory but reached an even lower low temperature: -3°F at about 4:00 a.m. on January 22, with temperatures staying below 10°F until almost 11:00 a.m. that day.[4] These very cold, though certainly not

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[3] https://www.wunderground.com/history/daily/us/ky/louisville/KSDF/date/2025-1-21 and https://www.wunderground.com/history/daily/us/ky/louisville/KSDF/date/2025-1-22.

[4] https://www.wunderground.com/history/daily/us/ky/lexington/KLEX/date/2025-1-21 and https://www.wunderground.com/history/daily/us/ky/lexington/KLEX/date/2025-1-22.

unprecedented, temperatures had a profound impact on demand, reaching a peak hourly demand of 6,814 MW just after sunrise on the morning of January 22; intra-hourly loads reached 7,000 MW.[5] That peak was roughly equivalent to the Companies' 2014 Polar Vortex peak of 7,114 MW after adjusting for the departed KU municipal customers, and it was somewhat higher than the roughly 6,600 MW Winter Storm Elliott peak in December 2022 after accounting for the Companies' first-of-its-kind load shedding.

Importantly, the Companies experienced no load shedding, did not reach an energy emergency status, and did not have to request physical curtailment from their Curtailable Service Rider customers during this recent polar vortex event. The Companies' coal and gas fleet had excellent overall performance; even the Companies' secondary combustion turbines ("CTs") started successfully on the morning of January 22. The Companies experienced no pressure issues or other operational concerns on the Texas Gas pipeline. The Companies experienced a temporary pressure drop on the Texas Eastern pipeline the evening of January 21 Tuesday at the E.W. Brown Generating Station during a transmission-driven generation redispatch that caused the Companies to draw more hourly gas than planned with Texas Eastern for the Brown CTs, but it did not materially affect the Companies' ability to operate their units. The transmission issue resolved overnight, and the Companies drew even more gas from Texas Eastern on Wednesday morning, as planned, with no issues.

Indeed, because the Companies' units performed so well and prices in neighboring regions were sufficiently high during this event (called Winter Storm

[5] Peak load occurred during the 8:00 a.m. hour. Sunrise that day was 7:55 a.m.

Enzo), the Companies were able to sell enough power off-system that week (January 19-25) to achieve an off-system sales ("OSS") margin of $6.3 million. That is almost as much OSS margin as the Companies anticipate achieving for the full year 2025 ($7 million), and it is a benefit to customers, who receive 75% of such margins through the Companies' Fuel Adjustment Clause mechanisms.[6]

Finally, I would note that the excellent gas supply and transportation performance the Companies experienced during Winter Storm Enzo is consistent with the Companies' experience during January 2024's Winter Storm Heather, during which the Companies experienced no reliability or operational issues related to gas supply or transportation.

Q. Do you have any other observation concerning Winter Storm Enzo that is pertinent to this proceeding?

A. Yes. Although all the Companies' units performed well within expectations during Winter Storm Enzo, I would emphasize the word "all." The Companies had *all* available resources operating entering the January 22 peak demand: 7,728 MW of the Companies' total 7,791 MW of resources were available, including an estimated 111 MW of possible Curtailable Service Rider ("CSR") curtailments. That is impressive performance, but compared to a 6,814 MW peak hourly load and a 230 MW spinning reserve requirement, it left only 684 MW of available resources to draw upon if needed. If even one large unit had a forced outage that removed the unit's entire capacity during peak demand on January 22 (e.g., Cane Run 7's 691 MW), the Companies would have been close to being unable to meet their contingency reserve obligation under their

[6] I depend on Robert M. Conroy's expertise concerning the Companies' tariffs, including their Fuel Adjustment Clause and Off-System Sales mechanisms.

reserve sharing agreement with the Tennessee Valley Authority and thus an energy emergency status.

I would also note that, as Stuart A. Wilson discusses in his testimony concerning his Table 1, even with the resource portfolio approved in the 2022 CPCN-DSM Case,[7] adding only the announced 402 MW Camp Ground Road data center, the 125 MW Phase One of the BlueOval SK Battery Park, and a 19.4 MW existing customer expansion planned to be online in 2026, would place the Companies in the same reliability situation if another Enzo-level peak arrived (i.e., adding those new loads to the peak hourly load during Enzo).

I mention this not to cause alarm, but rather to observe that the Companies' current levels of capacity are not at all excessive with respect to existing customer loads. From my perspective as the leader of the group responsible for ensuring customers reliably receive service at all times, adding any significant amount of load, particularly firm, high load-factor load, *will* require additional resources to ensure the Companies can continue to serve customers reliably. Ideally, those resources would be dispatchable and available at any time and under any weather condition.

STATUS OF THE COMPANIES' PRIOR SOLAR PPAS

Q. For context concerning the Companies' current resource proposals, please provide an update regarding the status of the six solar PPAs into which the Companies have entered to date.

A. As the Companies recently stated in their 2024 Integrated Resource Plan ("IRP") proceeding, three of the six solar PPAs have terminated:

[7] Omitting the Companies' solar power purchase agreements for the reasons I discuss below.

- The project developer terminated the Clearway Song Sparrow PPA, one of the PPAs the Commission approved in the 2022 CPCN-DSM Case, due to the developer's inability to obtain land control for the required interconnection.
- The project developer terminated the Ragland PPA, which the Companies executed prior to the 2022 CPCN-DSM Case to serve five Green Tariff Option #3 customers, because the developer could not construct the project for the 2021 PPA price, and the customers would not agree to the developer's new price, which was over twice the original price.
- The Companies terminated the Gage PPA, one of the PPAs the Commission approved in the 2022 CPCN-DSM Case, because after engaging in negotiations under a price reopener provision the developer exercised, the Companies would not agree to a price that was approximately 60 percent higher than the original price.

Concerning the remaining three solar PPAs:

- For the Rhudes Creek Solar PPA, executed in late 2019 as part of Green Tariff Option #3 for 75% of the output, the developer has been unable to achieve the local approvals in Hardin County necessary to begin construction. If those approvals were achieved today, it is unlikely that the developer could develop the project for the 2019 contract price that the two customers agreed to as part of Green Tariff Option #3.
- The Nacke Pike PPA, one of the PPAs the Commission approved in the 2022 CPCN-DSM Case, faces challenges similar to Rhudes Creek related to Hardin

County approvals. Solar prices have also escalated significantly since the agreement was executed in early 2023.

- Although the Grays Branch PPA, executed in early 2023 as one of the PPAs the Commission approved in the 2022 CPCN-DSM Case, is not anticipated to face significant challenges related to local approvals in Hopkins County, the increase in solar prices is expected to result in a price reopener in accordance with the terms of the PPA.

Thus, of the six total solar PPAs into which the Companies have entered, including two into which the Companies entered prior to the 2022 CPCN-DSM Case, none has resulted in an actual project or a single kWh of energy to date (and three certainly never will). In addition to land control and local permitting and zoning challenges, recent dramatic increases in solar pricing mean that the three remaining solar PPAs' pricing is now significantly below the current market price for solar, making it less likely they would proceed even absent the other challenges. The Companies will continue to seek to advance these PPAs, but only if they are ultimately favorable to customers.

Q. How has the Companies' experience with these six solar PPAs informed their view concerning execution risk?

A. The Companies' experience with these PPAs highlights the execution risk the Companies noted in the 2022 CPCN-DSM Case as an important reason to proceed with two solar projects to be owned by the Companies, namely the Mercer and Marion County solar facilities, in addition to the solar PPAs.[8] Of the more than 850 MW of total solar capacity for which the Companies contracted through these PPAs—some as

[8] *Id.* at 17.

long as five years ago—none of it has progressed, much less been built. If the Companies had been counting on these facilities to develop and produce energy as initially anticipated to maintain reliable service (rather than to serve primarily as fuel-price hedges), this execution risk turned lack-of-execution reality could have adversely affected customers.

That is not to say there is no place for PPAs, even solar PPAs, in the Companies' resource planning. But this experience shows that execution risk is real. Thus, particularly for resources that are (1) important to have available by a certain date to help ensure reliable service and (2) present financing or development challenges that might cause PPA counterparties to delay or abandon planned projects, it is preferable for the Companies to own the facilities. As I discuss below, this is a key reason why the Companies are proposing to self-build their proposed 400 MW, four-hour (1,600 MWh) Cane Run BESS rather than seek battery storage contract proposals.

<u>OVERVIEW OF THE COMPANIES' MAY 2024 RENEWABLE ENERGY RFP</u>

Q. Please describe the content, timing, and distribution of the Companies' May 2024 renewable energy RFP.

A. On May 1, 2024, the Companies issued an RFP for renewable energy, seeking non-firm renewable energy from solar, wind, or hydroelectric sources, with a minimum nameplate capacity of 75 MW available no sooner than 2026. The Companies considered PPAs, asset purchases (new or existing), and build-transfer transactions. Responses were due on June 21, 2024, giving potential respondents seven weeks to respond. The Companies sent the RFP to 165 potential respondents, which included entities across broad sectors of the electric generation industry, industry publications, and organizations.[9] The Companies also issued a press release on May 1, 2024, which included a link to the RFP on the Companies' website.[10] News of the press release circulated in the industry, including in the widely read *S&P Global Market Intelligence*.[11]

Q. Did the May 2024 RFP seek proposals for resources other than renewable energy (e.g., energy storage or fossil-fueled resources)?

A. No, because it was not necessary to solicit proposals for non-renewable energy resources to ensure the Companies would have a reasonable and robust set of market-priced resource options to consider and analyze.

First, as I described at length in my testimony in the 2022 CPCN-DSM Case, the Companies issued a full-spectrum RFP for supply-side resources of all types in June 2022 ("June 2022 RFP"). The June 2022 RFP sought proposals for capacity and energy from any and all technologies, including energy storage, with a minimum nameplate value of 100 MW available no sooner than 2025. Potential respondents had eight weeks to respond. The Companies issued the June 2022 RFP to 146 potential respondents across broad sectors of the electric generation and storage industries. The Companies also sent the RFP to a number of industry publications and organizations, issued a press release containing a link to the RFP on the Companies' website, and obtained coverage

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[9] The Companies provided their RFP to the Electric Power Supply Association (EPSA), Energy Central, Environmental Leader, North American Energy Marketing Association (NAEMA), Solar Energy Industries Association (SEIA), and Wind Energy Association.

[10] The Companies' May 1, 2024 press release concerning the RFP is available at https://lge-ku.com/newsroom/press-releases/2024/05/01/lge-and-ku-pursuing-new-opportunities-add-renewable-energy. The link to the RFP became inactive shortly after the RFP due date.

[11] Julia Reign Reyes, S&P GLOBAL MARKET INTELLIGENCE, *Ky. Utilities Seek Bids for New Renewable Energy Supplies* (May 1, 2024), available at CIQ Pro: Ky. utilities seek bids for new renewable energy supplies. *See also, e.g.*, Sean Wolfe, RENEWABLE ENERGY WORLD, *LG&E and KU Issues Request for Renewable Projects Over 75 MW* (May 3, 2024), available at https://www.renewableenergyworld.com/news/lge-and-ku-issues-request-for-renewable-projects-over-75-mw/.

from the industry press. The Companies' efforts resulted in 101 proposals across 39 projects from 22 respondents. *The only proposals for fossil-fueled resources the Companies received were their own self-build proposals*; all the rest were renewable, energy storage, or a combination thereof.

In the intervening two years, as Lonnie E. Bellar and David L. Tummonds discuss, the market for gas-fired resources has significantly tightened and costs have markedly increased due to much more demand for gas-fired turbines, whether simple- or combined-cycle, than the three manufacturers of such resources—globally—can supply. Moreover, the Companies already have an established relationship with the selected vendor for the Mill Creek 5 NGCC power island, and as Mr. Tummonds describes, there are cost and operational efficiencies associated with using the same vendor's technology for the proposed Brown 12 and Mill Creek 6 NGCCs. Therefore, there was no need to issue, or value in issuing, an RFP for such resource proposals.

Regarding possible battery energy storage agreements—essentially PPAs for battery storage—the Companies received a number of such proposals in response to their June 2022 RFP. The Companies elected to pursue, and the Commission approved, their own self-build battery energy storage system at the E.W. Brown Generating Station ("Brown BESS") rather than a battery storage contract for a number of reasons that remain true today; indeed, they are even more important today. First, there is an important element of execution risk with such contracts. As I discussed above, none of the Companies' executed solar PPAs have resulted in any solar project advancing at all, much less actually producing energy. In contrast, the Companies' two owned solar projects are advancing. Similarly, a battery storage contract could fail to result in a

BESS being available to serve the Companies' customers in a timely manner, if at all. Given the Companies' need to have significant amounts of BESS capacity available to serve anticipated load reliably, such execution risk is unacceptable, making a BESS owned by the Companies, like the proposed Cane Run BESS, the only viable battery option. Second, I have learned from my colleagues at other utilities that battery services contracts can present unforeseen challenges that, had the utility personnel known about them in advance, they would have attempted to address in the agreement, such as limits or changes to charging and discharging schedules that can complicate or adversely affect the utility's plans for efficient use of the battery services. Finally, the Companies continue to desire to gain operational experience with these facilities at utility scale. Thus, there was no need to seek, or value in seeking, such proposals through the May 2024 RFP.

Regarding pumped hydro storage, as the Companies stated recently in their 2024 Integrated Resource Plan proceeding, they are aware of the Lewis Ridge Pumped Storage project, and the Companies are currently working with Rye Development to evaluate the feasibility of the project and its cost relative to other technologies such as lithium-ion batteries. Therefore, there was no need to request energy storage proposals in the May 2024 RFP.

Finally, regarding possible nuclear proposals, the Companies received no nuclear project proposals in response to the June 2022 RFP. Considering the nationwide need for generation capacity generally, particularly dispatchable assets, there is no reason to expect that the Companies would receive any proposals, whether competitive or otherwise, from existing nuclear assets today.[12] Although small modular nuclear reactors are a promising technology, they are not yet a proven technology or commercially available, and there is no reason to expect they will be by the time the Companies will need them to serve the load included in the Companies' 2025 CPCN Load Forecast presented by Mr. Jones. Therefore, there was no need to request, or value in requesting, nuclear proposals in the May 2024 RFP.

For these reasons, the Companies determined it was appropriate for the May 2024 to seek proposals for renewable energy only. I believe this approach resulted in a full complement of resource alternatives for Mr. Wilson and his team to analyze to ensure the Companies can continue to provide safe and reliable service at the lowest reasonable cost.

Q. Please describe the RFP responses the Companies received.

A. A total of 17 parties responded to the RFP. Many of the projects had multiple options for term, size, or proposed commercial date, resulting in a total of 48 proposals across 22 different projects, all of which our group delivered to the Generation Planning group

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[12] *See, e.g.,* North American Electric Reliability Corp., "2024 Long-Term Reliability Assessment, December 2024" at 6 ("In the *2024 LTRA,* NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement."), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed Jan. 9, 2025); *id.* at 19 ("As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable.").

for analysis, which Mr. Wilson discusses. The table below summarizes the RFP responses.

Technology	Number of Proposals by Start Year			Nameplate Capacity (MW)	Price
	<=2028	2029	2030+		
Solar	27	1	0	40-600	[redacted]
Solar Asset Development	7	0	0	89-600	[redacted]
Solar w/ 4-hr BESS Option	6	0	0	115-400	[redacted]
Solar w/ 8-hr BESS Option	1	0	0	400	[redacted]
Solar + 4-hr BESS	1	0	0	150	[redacted]
Wind w/ Solar Option	0	2	0	600-800	[redacted]
4-hr BESS	1	0	0	120	[redacted]
Pumped Hydro	0	0	2	287	[redacted]

Q. What were the trends in solar pricing compared to the Companies' June 2022 RFP?

A. Consistent with the pricing issues the Companies have encountered concerning their previously executed solar PPAs, the May 2024 RFP respondents' solar PPA offer prices were generally 50% higher than similar offers the Companies received in response to their June 2022 RFP. Notably, as I discussed in my testimony in the 2022 CPCN-DSM Case, the solar PPA offers the Companies received in response to their June 2022 RFP were generally at least 30% higher than similar offers the Companies received in response to their 2021 RFP despite the intervening enactment of the federal Inflation Reduction Act.

This steady upward trend in solar PPA pricing being offered to the Companies is consistent with broader market trends since 2020. One such measure of broader solar PPA market trends is LevelTen Energy's PPA Price Index for North America, which reports solar P25 PPA prices.[13] (P25 prices represent the 25th percentile of price quotes, i.e., 75 percent of price quotes are above the P25 price level.) According to LevelTen, solar P25 PPA prices reached their lowest point, $27.26/MWh, in the first quarter of 2020.[14] More recently, those prices rose by 5.4% during the third quarter of 2024 and 10.4% year-over-year,[15] with typical solar P25 PPA prices at $56.58/MWh—a 108% increase in less than four years.[16] Those prices remained high in the fourth quarter of 2024, with the LevelTen solar P25 PPA price index reaching $56.76.[17] Therefore, the relative price increases reflected in the May 2024 RFP responses the Companies received are consistent with market trends and the Companies' own experience. Moreover, there are indications that this elevated solar pricing will persist for at least several years.[18]

Q. Did the Companies receive any offers to purchase renewable energy projects that are already under development?

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[13] Note that LevelTen's P25 North American index includes PPAs from areas that are much sunnier than Kentucky, such as Arizona, which tend to have lower-priced PPAs because there is more energy production over which to spread the cost of PPA facilities. That factor, in addition to the nature of P25 prices as discussed in the body of the text, makes the LevelTen North American average index price lower than PPA prices typically available to the Companies. But the *relative* changes in LevelTen North American index prices are still relevant to show that the Companies' recent solar PPA relative pricing change experience is not unique.

[14] LEVELTEN ENERGY, *Q1 2020 PPA Price Index* at 12, available at https://go.leveltenenergy.com/l/816793/2020-04-23/2dgx2/816793/11709/LevelTen_Energy_Q1_2020_PPA_Price_Index.pdf (accessed Jan. 10, 2024).

[15] *See* LEVELTEN ENERGY, *Q3 2024 PPA Price Index Executive Summary North America* at 7, available at https://www.leveltenenergy.com/ppa.

[16] Emma Penrod, UTILITY DIVE, *Renewable PPA Prices Continue to Rise — and May Do So Through 2030, Say LevelTen, Ascend Analysts* (Oct. 22, 2024), available at https://www.utilitydive.com/news/ppa-power-purchase-prices-wind-solar-levelten-ascend-analytics/730245.

[17] LEVELTEN ENERGY, *Q4 2024 PPA Price Index Executive Summary North America* at 7, available at https://go.leveltenenergy.com/l/816793/2025-01-27/3bgwky/816793/1738016621gyDcd5S8/2024Q4_NA_PPAPriceIndex_ES.pdf (accessed Jan. 30, 2025).

[18] *Id.* ("'It goes without saying that the recent year or two has seen turmoil in PPA prices,' Brandon Mauch, managing director of operations and strategy at Ascend Analytics, said Thursday. 'They have been elevated, and we are seeing some upward and downward drivers looking into the future. These drivers are expected to bring some calm, but in the near term we still see elevated prices.' PPA prices may begin to stabilize toward the later half of this decade, but may not begin to decline again until 2030 or beyond, Mauch said.").

A. Yes. Several respondents offered to sell the Companies projects being developed, and the Companies considered them. If the Companies acquired any such project, they would be purchasing the developer's initial project work, typically consisting of some amount of local permitting progress, limited land control via lease options, and an initial panel layout with limited design engineering. Particularly in the currently unfavorable solar pricing environment (as shown in Mr. Wilson's analysis), there would be little to no value in acquiring any of these projects.

First, unlike solar developers who offer PPAs and find leases to be economically preferable, the Companies prefer to own land where they locate long-lived generation assets. Ownership allows for the possible location of future generation assets where the Companies would already have built the necessary transmission infrastructure, and it eliminates future land-control uncertainties. This means the lease options included in these project acquisition offers are of no value to the Companies because they guarantee neither the price of acquiring the sites nor that the Companies can acquire the sites at all, regardless of price.

Second, the preliminary local permitting and design work are of limited value to the Companies, particularly if the Companies' eventual development of the sites might be years into future if solar prices or other factors make solar generation more competitive.

Therefore, my team recommended not pursuing any of these offers.

Q. What was the Companies' process for evaluating the RFP responses?

A. Under my supervision, the Companies' Power Supply group reviewed each RFP response for the required data and addressed any missing information with the applicable respondent(s). We then submitted the data to the Generation Planning group for analysis. Mr. Wilson's testimony describes the analysis Generation Planning used to evaluate the RFP responses. Ultimately, as Mr. Wilson notes, the Companies' analysis did not indicate that the Companies should pursue any proposals offered in response to the May 2024 RFP.

<u>NATURAL GAS SUPPLY AND TRANSPORTATION FOR PROPOSED NGCC UNITS</u>

Q. Are you confident that the Companies will be able to obtain sufficient gas supply to operate their existing simple-cycle combustion turbines, Cane Run 7, the approved but not yet constructed Mill Creek 5, and the proposed Brown 12 and Mill Creek 6 NGCCs?

A. Yes. The Companies' current, approved, and proposed gas units are served by multiple gas pipelines (Texas Gas Transmission ("Texas Gas"), Texas Eastern, and Tennessee Gas), all of which are supplied with gas from multiple gas basins. My team has communicated with all of the Companies' current and potential pipeline suppliers about the Companies' planned generation capacity additions and expanded gas supply requirements, and the consistent response the Companies have received is that there is ample gas supply available for the Companies' units. That confidence is reasonable considering the U.S.'s enormous domestic proved gas reserves,[19] production capability,[20] and technically recoverable resources.[21]

Q. How do the Companies manage natural gas price risk for their existing NGCC unit, Cane Run 7?

A. To hedge against fuel price volatility for Cane Run 7, the Companies purchase a portion of the unit's fuel on a forward basis, i.e., the Companies commit to the future payment of a set price for a quantity of gas molecules to be delivered at a particular location. The Companies currently purchase up to 50 percent of Cane Run 7's expected gas burn on a forward basis for the current year. The balance of natural gas is purchased daily on the spot market. For the following years one, two, and three, the Companies purchase 40-60 percent, 20-40 percent, and 0-20 percent, respectively, of the unit's minimum expected burn on a forward basis.

Q. Will the Companies' gas procurement strategy change once the Mill Creek 5 NGCC unit approved in Case No. 2022-00402 goes into service?

A. I expect that it will, and it could change again with the addition of Mill Creek 6 and Brown 12. The Companies do not have a "set it and forget it" approach to fuel procurement strategy; rather, Power Supply periodically reevaluates this strategy to

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[19] *See, e.g.,* U.S. Energy Information Administration, "U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2022" (Apr. 29, 2024) ("Proved reserves of U.S. natural gas increased 10%, from 625.4 Tcf at year-end 2021 to 691.0 Tcf at year-end 2022, establishing a new record for natural gas proved reserves in the United States for a second consecutive year."), available at https://www.eia.gov/naturalgas/crudeoilreserves/ (accessed Jan. 9, 2025).

[20] *See, e.g.,* U.S. Energy Information Administration, "Which states consume and produce the most natural gas?" (Oct. 30, 2024) ("In 2023, U.S. total consumption of natural gas was 32.62 trillion cubic feet (Tcf). … In 2023, the United States produced 37.80 Tcf of dry natural gas."), available at https://www.eia.gov/tools/faqs/faq.php?id=46&t=8#:~:text=In%202023%2C%20the%20United%20States,Mexico%E2%80%942.89%20Tcf%E2%80%947.6%25 (accessed Jan. 9, 2025).

[21] *See, e.g.,* U.S. Energy Information Administration, "Natural gas explained: How much natural gas is left" (July 16, 2024) ("EIA estimates in the *Annual Energy Outlook 2023* that as of January 1, 2021, the United States had about 2,973 trillion cubic feet (Tcf) of TRR of dry natural gas."), available at https://www.eia.gov/energyexplained/natural-gas/how-much-gas-is-left.php (accessed Jan. 9, 2025).

ensure the Companies can continue to dependably fuel these important units and provide reliable service at the lowest reasonable cost. My current expectation is that the Companies will seek to increase their forward gas purchases as their NGCC fleet grows. This would reduce potential spot-market price volatility the Companies' own increasing purchase volumes might create in those markets, which should help ensure fuel cost stability for customers over time.

Q. How will the Companies ensure they will be able to transport the gas they purchase to the proposed NGCC units?

A. The Companies will acquire a suite of firm gas transportation services from the pipelines serving the Brown and Mill Creek stations to ensure the Companies can reliably transport the gas they purchase to the proposed NGCCs. The pipeline that will serve the approved Mill Creek 5 NGCC and the proposed Mill Creek 6 NGCC is Texas Gas Transmission. There are two pipelines that currently serve Brown's simple-cycle combustion turbines, Tennessee Gas and Texas Eastern.

Q. What is firm gas transportation service, and how does it compare to non-firm transportation service?

A. Firm gas transportation service "guarantees gas delivery without interruption … at the customer's primary firm delivery point."[22] In contrast, non-firm, or interruptible, service provides no guarantee of delivery. There are various kinds of firm service available, including service with different amounts of notice required (e.g., no-notice service) and different seasonality. Different kinds of firm service have different pricing

[22] Interstate Natural Gas Association of America, "INGAA Service Primer Fact Sheet," available at https://ingaa.org/wp-content/uploads/2024/02/INGAA_ServicePrimer_FactSheet.pdf (accessed Jan. 10, 2025). *See also* 18 CFR 284.7(a)(3)(" Service on a firm basis means that the service is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service.").

and conditions, and the Companies work to ensure they acquire the firmness they need for reliable unit operation at the lowest reasonable cost. Most of the Companies' existing gas transportation contracts expire in 2027,[23] which will allow for a reexamination of and possible adjustments to the Companies' current suite of firm transportation services in the context of the approved Mill Creek 5 NGCC and any units the Commission approves in this proceeding.

Q. Is firm gas transportation service available for the NGCC units (Brown 12 and Mill Creek 6) proposed in this CPCN proceeding?

A. Yes. The Companies have held discussions with the pipelines serving Brown and Mill Creek and concluded sufficient firm gas transportation services are or will be available to reliably deliver natural gas to fuel the proposed NGCC units.

The Companies do not procure transportation services until receiving regulatory approvals to construct new units. Nonetheless, upon approval of the proposed NGCC units in this proceeding, the Companies anticipate sufficient transportation services will be available based on their recent communications with Texas Gas and Tennessee Gas. Conversely, if the proposed NGCC units are not approved, the Companies cannot guarantee firm transportation will remain available indefinitely, as the pipelines' capacity availabilities may change in the future.

Q. Would having gas transportation service for Mill Creek 5 and 6 on the same interstate pipeline system as Cane Run Unit 7 create a significant reliability risk?

A. The Texas Gas pipeline serving both sites is supported by an extensive system of multiple lines and compressors to ensure reliability. For example, in areas upstream

[23] These transportation contracts feature rollover rights to ensure opportunities for extension.

and downstream from Louisville, piping and valves connect multiple lines approximately every ten miles and the system is supported by the redundancy of compression equipment, with 30 compressors located from northeast of Trimble County to southwest of Mill Creek. Texas Gas system flows in this area are bidirectional, with seasonal or more frequent changes of flow direction based on demand. Texas Gas's nine gas storage fields in western Kentucky and southern Indiana further support system reliability and supply flexibility. The Mill Creek NGCCs will also be connected to Texas Gas at a different point than Cane Run Unit 7, eliminating a single contingency that would exist if all three units were served from a single pipeline interconnection.

The Companies acknowledge that during Winter Storm Elliott in December 2022 they experienced a first-of-its-kind pressure drop on the Texas Gas pipeline that seriously compromised their ability to operate Cane Run 7 and the Trimble County combustion turbines. As the Companies explained at length in the 2022 CPCN-DSM Case and the more recent Winter Storm Elliott investigation case, they have worked with Texas Gas to understand what went wrong, and Texas Gas has taken all reasonable steps to ensure it will not happen again. The Commission recognized the Companies' and Texas Gas's efforts in this regard in its recent Final Order in the Winter Storm Elliott investigation case.[24] In accordance with that Order, the Companies have and will continue to "remain in regular contact with their fuel suppliers to verify the status

[24] *Electronic Investigation of Louisville Gas and Electric Company and Kentucky Utilities Company Service Related to Winter Storm* Elliott, Case No. 2023-00422, Order at 25-27, 45 (Ky. PSC Jan. 7, 2025).

of critical equipment and emergency procedures before weather events such as Winter Storm Elliott to ensure steady access of fuel during severe weather."[25]

For these reasons, the Companies do not believe having Texas Gas serve Cane Run 7 and Mill Creek 5 and 6 will pose a significant service reliability risk.

Q. What are the operational characteristics of the Texas Eastern and Tennessee Gas pipelines, and what is the Companies' current commercial relationship with those pipelines?

A. The Texas Eastern pipeline system consists of 8,580 miles of pipeline connecting the Gulf Coast to markets in the northeastern U.S., and the Tennessee Gas system includes 11,760 miles of pipeline connecting the Gulf Coast and Mexico to the northeastern U.S. The Texas Eastern pipeline has bidirectional capability with two Bcf/day flowing past the Brown area. Tennessee Gas has one to two Bcf/day flowing through the area. The Companies have ongoing commercial transactions for gas transport to the Brown SCCTs with both Texas Eastern and Tennessee Gas, but do not have long-term firm transport agreements with either of the pipelines. Additionally, LG&E has an agreement with Tennessee Gas for a portion of its gas transportation requirements to serve its retail gas customers. The pipeline segment owned by the Companies that connects the interstate pipeline system to Brown would still be capable of connecting to the alternate interstate pipeline, regardless of the choice of either Texas Eastern or Tennessee Gas for the firm gas transport services for Brown NGCC. This would further support transport reliability during an interruption event on the pipeline selected for the transport service agreement.

[25] *Id.* at 27.

Q. For Brown 12, would the purchase of firm gas transport services be limited to the new unit?

A. The Companies will procure the appropriate breadth of firm transport services for the Brown 12 NGCC while also considering potential transport benefits for the seven existing Brown combustion turbines ("CTs"). Six of the seven CTs have dual-fuel capabilities for limited duration operation using fuel oil. The transport services for Brown 12 should complement the transport needs for the peaking units. For example, the transport services could be shifted to the peaking units in the event of an outage on Brown 12.

THE IMPORTANCE OF BATTERY STORAGE

Q. What is your view of the importance and likely use of the Companies' approved and proposed battery storage?

A. Based on my understanding of the load increases the Companies are forecasting and the resource portfolio the Companies are recommending, battery storage will have an important role in providing reliable service to customers for years to come. In the 2022 CPCN-DSM Case, the Companies requested, and the Commission granted, approval for the Brown BESS largely to help the Companies gain experience with BESS technology at utility scale in anticipation of increasing renewable energy penetrations, while also adding an element of additional system reliability.[26] Although that remains a useful role for batteries, the more pressing operational issue presented by rapidly increasing load, particularly high load-factor load, is how to ensure that the Companies can reliably serve peak loads with the proposed resource portfolio. The proposed Cane

[26] Case No. 2022-00402, Order at 18, 95-97 (Ky. PSC Nov. 6, 2023).

Run BESS and the approved Brown BESS will allow the Companies to store energy produced during off-peak periods and discharge that energy to serve daily peaks. Mr. Wilson can speak to the economics of adding BESS versus other resources, but from a Power Supply perspective, I believe adding the proposed BESS capacity will be important to ensure reliable service during peak periods, as well as the benefits it might offer for future integration of renewable energy resources at scale.

Q. Have you received useful advice from colleagues at other utilities that will aid the Companies in operating and dispatching the Brown and Cane Run BESS facilities?

A. Yes. My colleagues at the California ISO and Tennessee Valley Authority have emphasized that operating and dispatching battery storage includes fine-tuning the extensive settings associated with the battery resource to ensure optimal integration with existing resources. This includes matching the battery's response to other ramping resources under some conditions while allowing more rapid response under other system conditions. This is another reason that owning and operating BESS resources is preferable to entering into battery storage service contracts, which would likely not allow the Companies to gain this valuable experience, exercise this level of control, and most effectively optimize use of BESS resources.

CONCLUSION

Q. Do you have any recommendations for the Commission?

A. Yes. From my perspective as the Companies' Director of Power Supply, based on the magnitude and nature of the load the Companies are forecasting as explained by Mr. Jones, I believe the proposed resources for which the Companies are seeking approval in this case will enable the Power Supply team to continue providing the Companies' customers reliable service on an ongoing basis. If approved, we will continue working year-round and around-the-clock to use the proposed resources, the Companies' existing and approved resources, and energy markets to provide that reliable service at the lowest reasonable cost.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Power Supply for 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.

Charles R. Schram
____
Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of February 2025.

Caroline J. Davison
____
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY
PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

APPENDIX A

Charles R. (Chuck) Schram

Director, Power Supply
LG&E and KU Services Company
2701 Eastpoint Parkway
Louisville, Kentucky 40223

Professional Experience

LG&E and KU

Director, Power Supply	2016 – Present
Director, Energy Planning, Analysis & Forecasting	2008 – 2016
Manager, Transmission Protection & Substations	2006 – 2008
Manager, Business Development	2005 – 2006
Manager, Strategic Planning	2001 – 2005
Manager, Distribution System Planning & Eng.	2000 – 2001
Manager, Electric Metering	1997 – 2000
Information Technology Analyst	1995 – 1997

U.S. Department of Defense – Naval Ordnance Station

Manager, Software Integration	1993 – 1995
Electronics Engineer	1984 – 1993

Education

Master of Business Administration
University of Louisville, 1995

Bachelor of Science – Electrical Engineering
University of Louisville, 1984

E.ON Academy General Management Program: 2002-2003

Center for Creative Leadership, Leadership Development Program: 1998

Civic Activities

The Housing Partnership – Board of Directors, 2017 – Present

Leadership Louisville – Bingham Fellows class of 2020

Chuck Schram
Director, Power Supply
Power Supply
[redacted]

PPL companies

220 West Main Street
Louisville, KY 40202

May 1, 2024

Request for Proposals to Sell Renewable Energy (RFP)

Dear Colleague in the Development and Marketing of Electrical Power,

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (together the "Companies") are evaluating alternatives to provide least-cost long-term supply of renewable energy to serve our customers. The Companies are exploring additions no earlier than 2026 to enable the Companies to address potential EPA regulations, load growth, and diversification of the Companies' generation portfolio. The renewable energy may also be considered as a supply source for the Companies' Green Tariff participants. The additions sought in the RFP are projects producing non-firm renewable energy from solar, wind, or hydro sources. The Companies will consider purchase power agreements, asset purchases (new or existing), and build-transfer transactions. The RFP does not seek the addition of capacity resources (e.g., energy storage).

Each respondent should make its proposal as comprehensive as possible so that the Companies may make a thorough and definitive evaluation of the proposal's benefits to the Companies' customers without further contact with the respondent. However, the Companies reserve the right to request additional information.

Please provide your proposal consistent with the stated terms below. The resource(s) proposed in response to this RFP should provide a site-specific Generating Facility (which shall be defined for the purposes of this RFP as a device for the production of electricity that the Companies can designate as a Designated Network Resource (DNR), as such term is defined in the LG&E and KU Joint Pro Forma Open Access Transmission Tariff ("Companies' OATT").

This RFP is not a commitment to purchase and shall not bind the Companies or any affiliate of LG&E and KU Energy LLC in any manner. The Companies in their sole discretion will determine which respondent(s), if any, to engage in negotiations that may lead to a binding contract. The Companies shall not be liable for any expenses that respondents incur in connection with preparation of a response to this RFP or any requests for additional information associated with this RFP.

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The Companies will not reimburse respondents for their expenses under any circumstances, regardless of whether the RFP process advances to a successful conclusion or is abandoned by the Companies at the Companies' sole discretion.

1. **Background** – All proposals will be evaluated in the context of meeting customers' load in a reliable, least-cost manner. If the Companies determine that a proposal may be in the best interest of the Companies' customers, the Companies may enter into negotiations which may lead to the execution of a definitive agreement(s). The Companies will consider all applicable factors in evaluating proposals, including, but not limited to, the following to determine the least-cost proposal(s): (i) the terms of the proposal; (ii) respondent's creditworthiness; (iii) if applicable, the operating history or the development status of respondent's Generating Facility, including, but not limited to, the site chosen, permitting, and the status of an interconnection to the transmission grid; (iv) the anticipated availability of the energy; and (v) all other factors, such as the cost of interconnection or transmission that may affect the Companies' ability to reliably and cost-effectively serve the Companies' customers.

2. **Requirements** – The Companies are interested in alternatives to procure renewable energy no earlier than 2026. To be considered, each unique proposal and/or project **must**:

    2.1. Be deliverable to the Companies' transmission system; the Companies will assess any costs required to deliver energy generated outside the Companies' Balancing Area to the Companies' transmission system.
    2.2. Qualify as a DNR according to the Companies' OATT;
    2.3. Have a minimum term of 5 years and a maximum term of 30 years unless ownership of the Generating Facility by the Companies is proposed;
    2.4. Have at least a 75 MW nameplate rating (proposals smaller than 75 MW will not be considered);
    2.5. Comply with all industry standards applicable to the technology being proposed, including, but not limited to IEEE Std 2800™-2022 for inverter-based resources.

    Multiple proposals from multiple respondents may be selected to achieve an optimal generation portfolio for the future. The energy under each proposal must be generated from a defined source, a specific unit, or specific units that will qualify as a DNR. A respondent proposing energy from a resource connected directly to the Companies' transmission system must conform to the generation interconnection procedures in the Companies' OATT and must obtain a generation interconnection agreement for the Generating Facility in a timely manner. Third party respondents should not assume access to, or utilization of, existing sites owned by the Companies for siting proposed project(s).

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3. **<u>Key Terms and Conditions</u>** – Each respondent's proposal should contain the pricing, project location, resource type, performance characteristic and guarantees, financial security, and all other proposed terms and conditions necessary for the Companies to evaluate the proposal without further communication with the respondent. **All necessary information must be provided through an electronic submission of the attached data form(s) that correspond(s) to the proposal's generation technology and offer type. A separate data form must be included for each offer relative to resource size, term, commercial operation date, technology and option paring, price structure, etc.** Note that such data forms may be utilized in any filings with regulatory agencies (such as the Kentucky Public Service Commission) related to this RFP.

4. **<u>Project Description (Required Proposal Content)</u>** – Each proposal must contain a complete description of the proposed generation technology, project location, operating characteristics, transmission system interconnection point, etc.

5. **<u>Pricing Details (Required Proposal Content)</u>** – Proposed prices must be clear and quoted in U.S. dollars. If proposed pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included. Likewise, if the proposed pricing is cost-based, the nature of the costs to be included must be clearly stated. Each proposal must include the location of the Generating Facility but should NOT include transmission delivery costs for the proposed term across electric transmission systems. Respondents should assume the Companies will be responsible for all transmission costs that may be incurred to move the energy from the Generating Facility to, and on, the Companies' transmission system.

6. **<u>Metering and Monitoring (Required Proposal Content)</u>** – The Companies may require real time metering and monitoring of all generation resources. If so, the Companies desire, at the Companies' expense, to install equipment at the generator site to facilitate real time metering and monitoring. The respondent should state its desire and willingness to allow and cooperate with the Companies in establishing real-time monitoring and metering of generation, including the installation of Companies' equipment at the Generating Facility site.

7. **<u>Ancillary Services (Required Proposal Content)</u>** – If a definitive agreement is entered into with a respondent, the Companies will require the unrestricted right, under such definitive agreement, to the energy associated with the Generating Facility that is the subject of such respondent's proposal, including all ancillary services capable of being produced by the Generating Facility. If applicable, a respondent's proposal should describe any ancillary services, including, but not limited to, load following, spinning reserve, supplemental reserve, black start capability, frequency response, etc., included in such proposal.

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8. **Delivery (Required Proposal Content)** – The proposal shall state the required transmission paths to deliver energy from the Generating Facility to the Companies' transmission system. The energy must be deliverable to the Companies' transmission system. The respondent shall be and is responsible for all costs associated with the interconnection of the Generating Facility to the grid and the Companies will be responsible for the costs incurred moving the energy (including ancillary services) from the interconnection point to the Companies' transmission system and/or load.

9. **Environmental** – If a definitive agreement is entered into with a respondent, with respect to the sale of energy (including ancillary services) to the Companies under such definitive agreement, where permits are applicable for the product being sold, the respondent will be responsible for obtaining all necessary permits and complying with their requirements for the life of the agreement. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by respondent.

10. **Development Status (Required Proposal Content)** – Respondent shall provide a comprehensive narrative of the status of the development of any generation project intended to be used in a definitive agreement with the Companies. Respondent's narrative shall include the following:

    10.1. Comprehensive development and construction schedule (if applicable),
    10.2. Listing of all required permits and governmental approvals and their status,
    10.3. Listing of all required electric interconnection agreements and their status,
    10.4. Financing plan (if applicable), and
    10.5. Summary of key contracts (construction, major equipment, etc.), to the extent that they exist.

    Proposals demonstrating support from local government(s) or communities are preferred. Land control via purchase options instead of lease options is also preferred.

11. **Renewable Energy Certificates** – Any Renewable Energy Certificates ("REC") that are part of the proposal must be created from renewable facilities verified and approved by the proven renewable asset tracking systems associated with a major regional Independent System Operators ("ISO"). Applicable tracking systems are PJM's Generation Attribute Tracking System ("GATS") or MISO's Midwest Renewable Energy Tracking System ("MRETS"). The legal ownership of every REC so created is recorded and tracked by GATS or MRETS to assure its authenticity and single ownership.

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12. **Financial Capability (Required Proposal Content)** – Should the Companies elect to enter into a definitive agreement with a respondent who later fails to meet its obligations under such definitive agreement at any point in time, the Companies' customers may be exposed to the risk of higher costs. Therefore, each respondent is required to demonstrate in its proposal, in a manner acceptable to the Companies, the respondent's ability to meet all financial obligations to the Companies throughout the applicable development, construction and operations phases for the term of a definitive agreement.

    12.1. If a definitive agreement is entered into with a respondent, such respondent will be required to maintain, at all times during the term of such definitive agreement, an investment grade credit rating with either S&P or Moody's or have a parent guarantee from an investment grade entity that meets the approval of the Companies.

    12.2. If a definitive agreement is entered into with a respondent, the respondent will, upon execution of such definitive agreement, be required to post a letter of credit ("LOC") to protect the Companies' customers in the event of default by the respondent. The exact amount of a LOC will be subject to approval by the Companies based upon the Companies' models. If the Companies draw down the LOC amount at any time, the seller must replace the LOC to the original value within five days.

    12.3. For purchase power agreements, seller will be required to provide a deposit of $2,500 per megawatt of nameplate rating upon the execution of a definitive agreement. This deposit will be refunded upon commercial operation of the project. The deposit will be forfeited in the event seller does not meet contractual milestones and the agreement is terminated by the Companies or the seller in accordance with the definitive agreement.

RFP Schedule – All proposals must be complete in all material respects and be received no later than 4 P.M. EDT on June 21, 2024. All responses must be emailed to: 2024RFP@lge-ku.com.

RFP Issued	May 1, 2024
Proposals Due	June 21, 2024 at 4 P.M. EDT
Evaluation Completed	Est. October 31, 2024

Proposals will not be viewed until 4 P.M. EDT on June 21, 2024. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that one or more proposals are in their customers' best interests. Any subsequent definitive agreement(s) will be contingent on obtaining the necessary regulatory approvals.

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13. **Treatment of Proposals**

    13.1. The Companies reserve the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in any proposal received. The Companies also reserve the right to modify this RFP or request further information, as necessary, to complete their evaluation of the proposals received.

    13.2. Each respondent who submits a proposal does so without recourse against the Companies for either rejection by the Companies or failure to execute an agreement for purchase of energy (including ancillary services) for any reason. Each respondent is responsible for any and all costs incurred in the preparation and submission of a proposal and/or any subsequent negotiations regarding a proposal.

14. **Confidentiality** – As regulated utilities, it is expected that the Companies will be required to release information contained in any proposal to various government agencies and/or others as part of a regulatory review or legal proceeding. The Companies will use reasonable efforts to request confidential treatment for such information to the extent it is labeled in the proposal as "Confidential." Please note that confidential treatment is generally more likely to be granted if limited amounts of information in a proposal, rather than large portions of the proposal, are designated as confidential. However, the Companies cannot guarantee that the receiving agency, court, or other party will afford confidential treatment to information contained in any proposal. Subject to applicable law and regulations, the Companies also reserve the right to disclose proposals to their officers, employees, agents, consultants, and the like (and those of its affiliates) for the purpose of evaluating proposals. Otherwise, the Companies will not disclose any information contained in the respondent's proposal that is marked "Confidential," to another party except to the extent that (i) such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction, or (ii) the Companies subsequently obtain the information free of any confidentiality obligations from an independent source, or (iii) the information enters the public domain through no fault of the Companies.

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15. **<u>Contacts</u>**

Chuck Schram, Director, Power Supply
LG&E and KU Energy LLC
Power Supply
220 West Main Street
Louisville, KY 40202

Phone: [redacted]

In closing, I look forward to your response by 4 P.M. EDT on June 21, 2024, and the possibility of doing business with you to meet the Companies' future power requirements. Please contact me if you have any questions and would like to discuss further. For immediate concerns in my absence, please contact James Frank, [redacted].

Sincerely,

Chuck Schram
Director, Power Supply

LG&E and KU RFP Data Form		
PPA - Renewable Generation		
Note to respondent: Provide a separate data form for each different proposal or "Term of Contract". MW to be stated as a NET AC value at the interconnection point.		
	Response	**Units**
Respondent		text
Product and Generation Characteristics:		
Generation Source Description		text
Transmission Interconnection Point of the Source		text
Point of Interconnection to the Grid		text
Start Date of PPA		mm/dd/yyyy
Term of PPA		years
Purchase Option Year (if applicable)		year
Nameplate Amount		MW
Annual Output Degradation		as a % of Output per year
Summer Output Amount		MW
Summer Maximum Dispatch Output Amount (if applicable)		MW
Summer Minimum Dispatch Output Amount (if applicable)		MW
Guaranteed Summer On-Peak Output (2PM to 5PM EDT)		MW
Winter Output Amount		MW
Winter Maximum Dispatch Output Amount (if applicable)		MW
Winter Minimum Dispatch Output Amount (if applicable)		MW
Guaranteed Winter On-Peak Output (6AM to 9AM EST)		MW
Annual Production Capacity Factor		%
Output in 10 minutes (if applicable)		MW
Guaranteed Minimum Ramp Capability (if applicable)		MW/minute
Control of Ramp Capability:		
min ramp rate up (if applicable)		MW/minute
min ramp rate down (if applicable)		MW/minute
Start-up time to minimum capability (if applicable)		minutes
Start-up time to maximum capability (if applicable)		hours
Minimum run time per operation period (if applicable)		hours
Minimum down time per shutdown event (if applicable)		minutes
Other cycling constraints (if applicable)		text
Constraints on production time (if applicable)		text
Forced Outage Rate		%
Guaranteed Availability		%
Maximum number of annual curtailable hours		hours/year
Planned Outage Schedule		text
Projected hourly electric energy production profile for a typical year over the term provided electronically.		Y/N
(intentionally blank)		
Pricing Information (provide a separate pricing form if applicable):		
Provide pricing to permit full understanding of all costs associated with a PPA which may include but are not limited to:		
Fixed energy price over the term		$/MWh
Escalating energy price starting in year 1 of the term		$/MWh
Escalating energy price rate		% per year
Purchase option price		$
END OF FORM	END OF FORM	END OF FORM

LG&E and KU RFP Data Form		
Sale Offer - Renewable Generation		
Note to respondent: Provide a separate data form for each different proposal or "Term of Contract". MW to be stated as a NET AC value at the interconnection point.		
	Response	**Units**
Respondent		text
Product and Generation Characteristics:		
Generation Source Description		text
Transmission Interconnection Point of the Source		text
Point of Interconnection to the Grid		text
Sale Date		mm/dd/yyyy
Nameplate Amount		MW
Annual Output Degradation		as a % of Output per year
Summer Output Amount		MW
Summer Maximum Dispatch Output Amount (if applicable)		MW
Summer Minimum Dispatch Output Amount (if applicable)		MW
Guaranteed Summer On-Peak Output (2PM to 5PM EDT)		MW
Winter Output Amount		MW
Winter Maximum Dispatch Output Amount (if applicable)		MW
Winter Minimum Dispatch Output Amount (if applicable)		MW
Guaranteed Winter On-Peak Output (6AM to 9AM EST)		MW
Annual Production Capacity Factor		%
Output in 10 minutes (if applicable)		MW
Guaranteed Minimum Ramp Capability (if applicable)		MW/minute
Control of Ramp capability:		
min ramp rate up (if applicable)		MW/minute
min ramp rate down (if applicable)		MW/minute
Start-up time to minimum capability (if applicable)		minutes
Start-up time to maximum capability (if applicable)		hours
Minimum run time per operation period (if applicable)		hours
Minimum down time per shutdown event (if applicable)		minutes
Other cycling constraints (if applicable)		text
Constraints on production time (if applicable)		text
Forced Outage Rate		%
Guaranteed Availability		%
Maximum number of annual curtailable hours		hours/year
Planned Outage Schedule		text
Projected hourly electric energy production profile for a typical year over the term provided electronically.		Y/N
(intentionally blank)		
Pricing Information (provide a separate pricing form if applicable):		
Provide pricing to permit full understanding of all costs associated with an asset sale which may include but are not limited to:		
Asset purchase price		$
Fixed O&M costs		$ per year
Variable O&M costs		$/MWh
Major maintenance costs		$ per event
Installation costs for Electric Transmission		$
Installation costs for Electric Interconnection		$
Other Installation costs		$
Other ongoing costs - Property taxes		$ / year
Other ongoing costs - Insurance		$ / year
Other ongoing costs - other		$ / year
END OF FORM	END OF FORM	END OF FORM

The entire Exhibit CRS-2 is Confidential and provided separately under seal.