COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2025 JOINT INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	)	**Case No. 2025-00087**

SIERRA CLUB'S COMMENTS ON EAST KENTUCKY POWER COOPERATIVE, INC.'S 2025 INTEGRATED RESOURCE PLAN

PUBLIC VERSION

Sierra Club respectfully submits these comments on the East Kentucky Power Cooperative ("EKPC") 2025 Integrated Resource Plan ("2025 IRP"). We find that there are many flaws with the plan, primarily its lack of exploration of other alternatives at the Company's coal units and other replacement alternatives to the new natural gas combined cycle plant (NGCC) at the Cooper coal plant site.

An IRP should be a space for thoughtful consideration and testing of major resource decisions; unfortunately, in this case, EKPC has predetermined these major resource decisions beforehand. Simply put, this is putting the cart before the horse. In addition, EKPC has not provided sufficient opportunity for battery storage to fulfill future capacity needs, despite the resource being an attractive option. Due to these major flaws, the Commission should reject the IRP.

Finally, we also discuss concerns with the modeling of a scenario with 1 GW of additional load in response to Commission Staff. We find that the results of this modeling are dubious, largely because EKPC understates the costs of new gas resources. We also discuss the need for transparency with stakeholders when modeling new large loads in the future, such as data centers.

I. Summary of EKPC's modeling approach

The 2025 IRP includes major changes to EKPC's coal units and a major new gas resource. In its preferred plan, EKPC has elected to co-fire the coal units Cooper 2 and Spurlock 1-4 with natural gas, mothball Cooper 1 until 2032, and construct a new NGCC at the Cooper site.[1] As part of the IRP, the Company conducted capacity expansion and production cost modeling using the RTSim model. In general, capacity expansion modeling allows for economic optimization of new resource builds when capacity needs arise, subject to the utility or modeler's constraints. The production cost step is where portfolios developed in capacity expansion modeling are then dispatched on an hourly basis to arrive at the total costs to customers (or revenue requirements) for various scenarios and sensitivities.

EKPC's capacity expansion modeling was conducted assuming many decisions were already in place. The co-firing of Cooper unit 2 and Spurlock units 1-4 with natural gas was hard-coded in the model, thus the IRP did not consider any other options for these coal units.[2] EKPC also pre-set the model to assume that Cooper Unit 1 would be in "mothball" status until 2032 with the Cooper CCGT coming online in 2030.[3] The Company did not consider any coal unit retirements prior to 2032 (for Cooper 1) and it did not consider full gas conversion at any of

[1] Company Response to PSC 2-10; Company Response to PSC 2-23; EKPC IRP pp. 138-139.
[2] Company Response to PSC 2-10.
[3] Company Response to AG 1-25b.

the units.[4] With these pre-modeling determinations to co-fire nearly all of the coal units and build a new NGCC, the model could only optimize for other new builds around those large resource decisions.

One key assumption of capacity expansion modeling is the load forecast which determines the capacity need, and by extension, how much capacity the model looks to build. In its most recent load forecast, EKPC projected that energy sales would increase significantly, at an average of 1.3 percent per year from 2025 through 2039—more than double the historical growth rate from 2009 through 2023.[5] This growth is largely driven by projected increases in residential and large commercial sales. EKPC did not incorporate new data centers in its IRP filing but it did perform the modeling of a scenario with 1 GW of new large load (or a hypothetical data center) in response to a request by Commission Staff.[6] This modeling found that nearly 1,500 MW of new NGCC capacity would be required to serve this new load.

Sierra Club has no concerns with EKPC using capacity expansion and production cost modeling in keeping with best practices; but we take issue with the assumptions and methodology employed by EKPC when conducting that modeling. In our comments below we address the key flaws in the Company's modeling approach in the IRP. We also discuss the modeling of a hypothetical scenario where there is 1 GW of new large load, in response to a Staff data request. We find that the modeling results provided in response to this request were not justified, and as a result they should not be used in support of a resource plan in the event of large load growth..

[4] Company Response to SC 2-10.
[5] EKPC IRP, Technical Appendix, Volume 1, Load Forecast, p. 2.
[6] Company Response to PSC 1-1.

II. The IRP should consider full gas conversion or retirement of some its coal units

When making a major, long-term investment decision, it is imperative to consider alternatives for comparison to make an informed and robust decision. Unfortunately, in this IRP, EKPC has predetermined major resource decisions rather than justify these choices by exploring alternatives in the modeling. The Company did not model any other options for its six coal units, nor did it consider alternatives to the new NGCC plant (which we discuss further in the next section). We understand that the Commission award the CPCN for these projects in July; however, this was long after the IRP modeling was conducted and the document was filed. By hard-coding these projects, the optimization or capacity expansion modeling in the IRP is rendered close to meaningless for the near term because major resource decisions are taken as a given rather than justified by modeling other options. As EKPC states:

> The resource optimization was run for the 2025 through 2030 time period. During that period, EKPC has no plans to retire any generation units given its need for additional capacity. Conversion of generation was included in the IRP modeling base case and matched the CPCNs requested for natural gas co-firing of Spurlock units 1 through 4 and Cooper unit 2. [7]

The Company decided to mothball Cooper 1 as an energy-only resource and co-fire all of its remaining coal units with natural gas; but it should have also considered full gas conversion (i.e. only 100 percent gas burn) or retirement of some of its coal units. In particular, we explain below that the poor performance and high costs of Cooper 1 should

[7] Company Response to PSC 2-10.

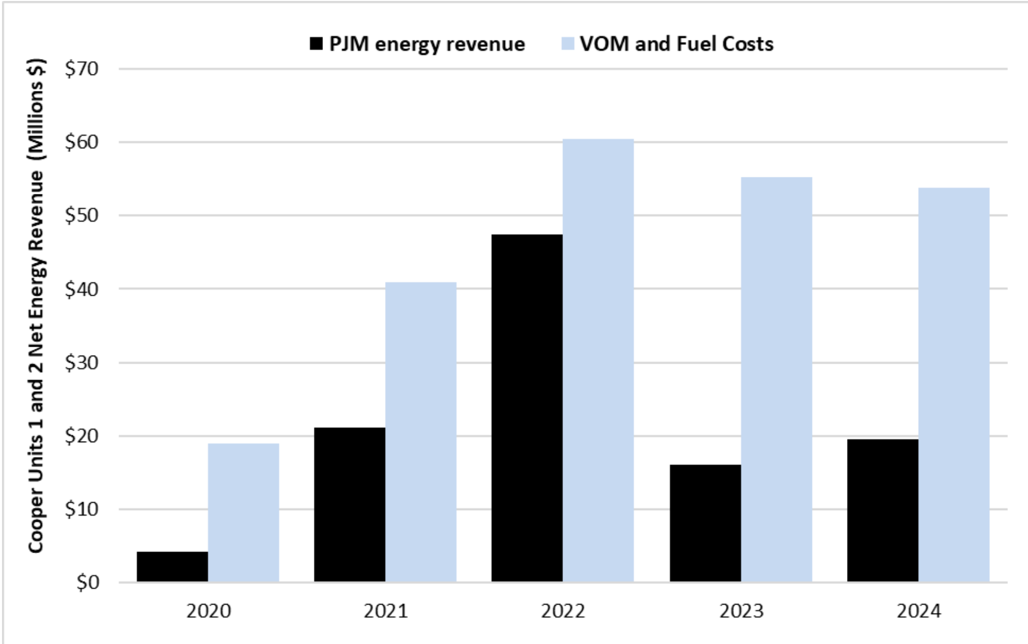
lead to its retirement and that similar circumstances for Cooper 2 and Spurlock 1 and 2 should lead EKPC to consider full gas conversion or retirement of these units.

A. EKPC should consider full gas conversion or retirement of Cooper 2 and earlier retirement of Cooper 1.

In its preferred plan, the Company allows for 100 percent gas at Cooper Unit 2, but with the possibility of co-firing with coal, despite its uneconomic performance running on coal.[8] The Company also plans to mothball Cooper 1 and use it essentially as a backup resource. EKPC should have considered both units for retirement and also considered Cooper 2 for full gas conversion, rather than leaving the door open for further coal usage. In order to be economic in a wholesale market, coal units should at a minimum generate more energy revenue than they cost to produce. Because ratepayers are paying for the units' operating costs and benefitting from the market revenue from the units' sales, if the former outweighs the latter then ratepayers are paying more for energy than they should. Unfortunately, that is the case for the Cooper plant, which has been operating at a loss on the energy market for at least the past five years as shown in Figure 1.[9]

[8] Company Response to PSC 2-10; Company Response to SC 2-10.
[9] Company Response to SC 1-8.

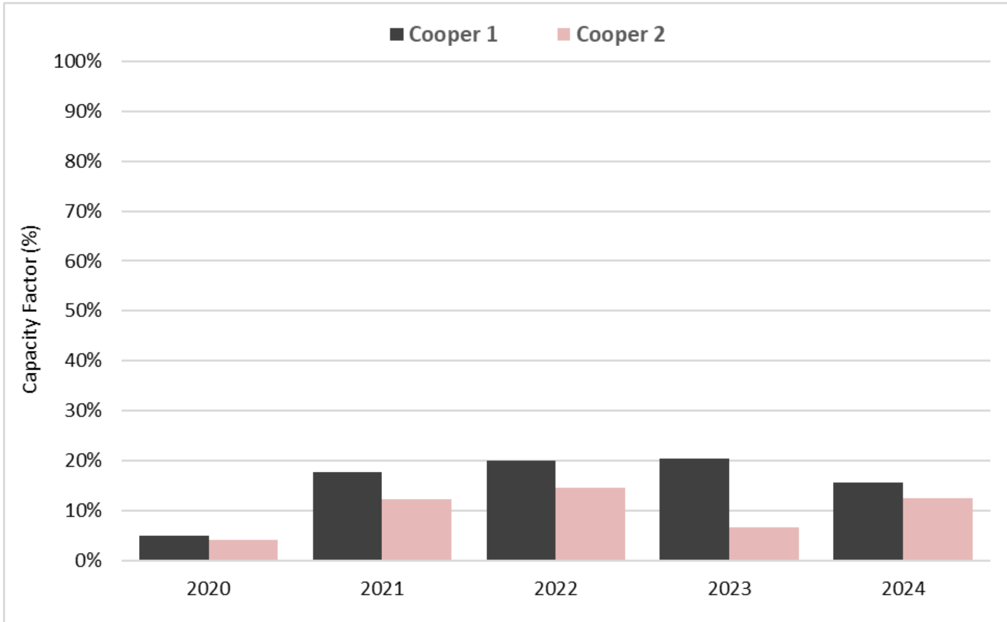
Figure 1: Plant Cooper Energy Revenues and Costs ($mil)[10]



These units are losing money and costing ratepayers because they both operate as peaking units while running on coal—as shown below in Figure 2. The units have operated at an average of a 13 percent capacity factor from 2020 through 2024, with the highest level in the past five years being 20 percent for Cooper 2 in 2022 and 2023.

[10] Company Response to SC 1-8.

Figure 2: Cooper Units 1 and 2 Historical Capacity Factor[11]



Cooper Unit 2 has operated the least frequently of any of the EKPC's units because it has high fuel costs and is highly inefficient, therefore it is costly to dispatch. The fuel costs in 2024 were nearly [redacted] per MMBtu, [redacted] the price of natural gas at that time.[12] Over the past five years, Cooper Unit 2 has an average heat rate of above 11 MMBtu/MWh, the highest of all the EKPC coal units except Cooper 1.[13] This means that in terms of *fuel costs only* the unit costs [redacted] per MWh to run on coal. Given the unit's high costs and poor performance—leading to negative net energy revenues—the Company should have at least considered converting the unit fully to gas or retiring it fully.

Cooper 1 has also experienced poor performance in recent years. As with Cooper 2, it has run at a low capacity factor (see above) and along with Cooper 2 had energy market losses—

[11] U.S. Energy Information Administration ("EIA") Forms 860 and 923 data for summer capacity (MW) and net generation (MWh), available at: https://www.eia.gov/electricity/data/eia860/ and https://www.eia.gov/electricity/data/eia923/.
[12] EKPC IRP, p. 93 CONFIDENTIAL.
[13] U.S. EIA Forms 923 data for net generation (MWh) and fuel use (MMBtu), available at: https://www.eia.gov/electricity/data/eia923/.

variable cost of production is higher than the energy market revenue. However, the Company has no plans to retire Cooper 1, but considers the unit mothballed and starting in 2032 replaces it with a new CCGT.[14] No other option was modeled in the IRP. The Company should have at least considered retiring Cooper Unit 1 in its modeling prior to 2032 given the unit's poor performance. It is also curious why EKPC needs a backup resource that apparently would not count towards its PJM capacity requirement.[15] The unit is still expected to cost roughly [redacted] per year until it is retired.[16] Surely, there are better uses of ratepayer money than paying for a unit to merely sit on standby for energy-only purposes.

B. EKPC should consider other options for Spurlock, in particular units 1 and 2.

The Company should also consider alternative options, at the minimum a full gas conversion, for some of the Spurlock units. The plant has lost money on the energy market in the past two years.[17] In addition, Spurlock Units 1 and 2 have had consistently higher heat rates than the other two units.[18] A heat rate is the main indicator of a unit's efficiency, or its ability to convert heat into electricity. The higher a heat rare, the more fuel is required to produce the same amount of MWh, and therefore the less efficient the unit. By extension, a less efficient unit is more costly to operate on a per MWh basis. Given the low efficiency of Spurlock units 1 and 2, EKPC should examine them more closely. Unfortunately, the IRP falls widely short of a close examination by simply assuming all of the units are co-fired, along with the necessary capital investments needed to conduct this operation at the plant.

[14] Company Response to AG 1-25b.
[15] Company Response to AG 2-25.
[16] EKPC IRP, p. 93 CONFIDENTIAL.
[17] Company Response to SC 1-8.
[18] U.S. EIA Forms 923 data for net generation (MWh) and fuel use (MMBtu), available at: https://www.eia.gov/electricity/data/eia923/.

The Company should have modeled alternative portfolios to assess the best options at its coal units. By predetermining the decisions at these units, it removes the usefulness of the IRP process which is a forum for exploring a multitude of options to achieve a low-cost, low-risk plan for ratepayers.

III. The selection of new gas in the IRP is risky and batteries should have been seriously considered instead

In addition to assessing the economics of existing resources, EKPC should have used optimization modeling to determine the lowest-cost new resources. However, in the IRP, new resources such as the Hydro PPA, Liberty RICE, and Cooper NGCC were hard-coded into the base case, meaning that they were not chosen as optimal in the IRP modeling.[19] Once those resources are forced in the model, EKPC confirmed that there was "no longer a need for the Resource Optimizer to select a resource from the resource list," which effectively bypassed the optimization process.[20] By imposing these constraints on the model, the Company essentially nullified the model's ability to explore a full range of resource options, undermining the purpose of the modeling exercise and offering minimal additional information. We find it particularly problematic that the installation of Cooper NGCC was assumed. (Later, we discuss issues surrounding the modeling of the additional 1 GW of large loads in response to Commission Staff.)

A. Investing in a large new gas resource is risky, especially given the pressure on gas prices.

Building new gas-fired power plants carries a high risk that the plant will become uneconomic or a stranded asset later on. It exposes the Company and its ratepayers to price risk,

[19] Company Response to Staff 2-23.
[20] Company Response to Staff 2-23.

as natural gas prices are facing upward pressure. The IRP projects that gas prices at the Cooper NGCC will mostly be around [redacted].[21] However, in its August 2025 Short-Term Energy Outlook (STEO), the U.S. Energy Information Administration (EIA) projected the average Henry Hub natural gas price to rise from $2.20 per MMBtu in 2024 to $3.60 in 2025 and $4.30 in 2026—nearly double the price in 2024.[22] EIA attributes this upward pressure on prices to relatively flat domestic natural gas production combined with an increase in liquefied natural gas (LNG) exports, which are expected to grow from an average of 12 billion cubic feet per day (Bcf/d) in 2024 to 16 Bcf/d in 2026.[23] The IRP should account for the changing landscape of natural gas due to tightening supply of this fuel, rather than plan to build the NGCC under an [redacted]

A higher gas price outlook should not lead one to conclude that co-firing Cooper unit 2 with coal and gas will decrease costs relative to full gas conversion. It would only be advantageous to mix in coal with natural gas at the unit if coal were cheaper than gas on a per MMBtu basis. [redacted]

[21] EKPC IRP, p. 106 CONFIDENTIAL.
[22] U.S. Energy Information Administration. August 2025. *Short-Term Energy Outlook (STEO)*. Available at: https://www.eia.gov/outlooks/steo/archives/Aug25.pdf.
[23] *Id.*

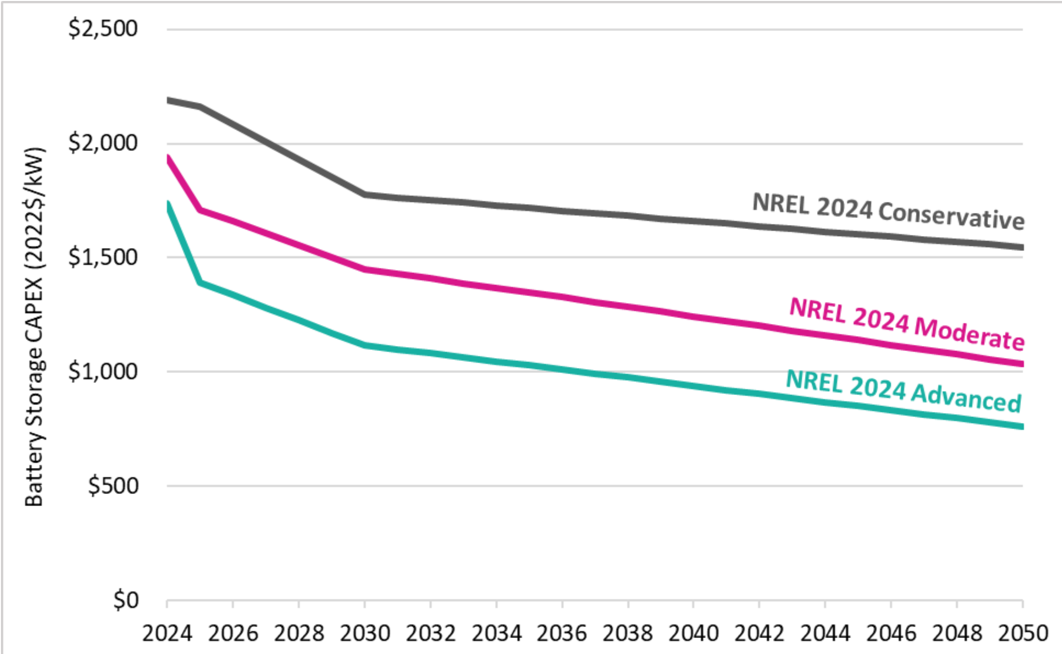
B. Battery storage was unfairly handicapped as a resource option in the IRP modeling.

EKPC's IRP does not add new battery storage; this result is not surprising given that the resource was not given sufficient opportunity in the model for several reasons: 1) as discussed above, major resources were forced in the model, limiting options for selection of other new resources; 2) battery capital costs were overstated in the IRP; and 3) batteries were not modeled in a modular fashion but only allowed to be added in a massive quantity. Throughout the United States, battery storage resources are increasingly becoming a go-to capacity resource. As of July 2025, approximately 7.4 gigawatts (GW) of battery storage were installed this year, with an additional 11.4 GW planned before the end of the year—making battery storage the second-largest source of new capacity additions after solar photovoltaics.[24] EKPC should seriously consider this type of resource in this and all subsequent IRPs rather than it be unfairly handicapped.

When assuming high capital costs for a resource, an optimization model is less likely to select that resource. EKPC's modeling assumes a projected capital cost of $2,190 per kW for battery storage resources, based on the National Renewable Energy Laboratory's ("NREL") 2024 Annual Technology Baseline ("ATB").[25] However, this capital cost assumption is based on the NREL 2024 ATB Conservative case, which is substantially higher compared to the Moderate and Advanced cases modeled by NREL (see Figure 3).

[24] EIA-860M, July 2025, available at https://www.eia.gov/electricity/data/eia860m/.
[25] Company Response to AG 2-5.

Figure 3. NREL 2024 capital costs for 4-hour battery storage resources (2022$/kW)[26]



EKPC should assume the Moderate case from NREL rather than the high case, allowing battery storage to be more competitive as a replacement resource.

EKPC should also drastically lower the size of battery installations. The Company only considered a 400-MW battery storage system in its modeling, which represents a large utility-scale project. This makes the resource only viable when there is a substantial capacity need. This constraint further disadvantages battery storage in the Company's modeling by ignoring the resource's flexibility and modularity, which allows deployment in small project sizes. EKPC defended this choice by pointing to 12 projects in the PJM interconnection queue that were over 400 MW.[27] But nearly 90 percent of the active battery storage projects listed in PJM's interconnection queue (341 projects in total) have capacities less than 400 MW, with an average

[26] NREL 2024 ATB, available at: https://atb.nrel.gov/electricity/2024/data.
[27] Company Response to SC 2-11.

capacity of approximately 115 MW.[28] Thus far this year, utility-scale battery storage additions in the United States have averaged approximately 80 MW in capacity.[29] Confusingly, the Company stated that it needed a 400-MW four-hour battery because it wanted to have 200 MW of capacity over an eight-hour period. But if that were the characteristic required, it could have modeled a 200-MW eight-hour battery instead, which would have provided the desired capacity for much lower capital costs than buying a 400-MW four-hour battery.

The effectiveness of any model depends heavily on its underlying assumptions. By focusing solely on a costly, 400-MW battery system, the Company is unnecessarily restricting the portfolio options by preventing its system from acquiring small, flexible battery storage projects as many other utilities are planning.

IV. The Commission should explicitly find that EKPC cannot rely on the additional modeling of 1 GW of large loads to justify new resource procurement

In response to Commission Staff's request, EKPC modeled an alternate plan to address a hypothetical 1 GW of new large load. This modeling resulted in almost 1,500 MW of new NGCC capacity in 2031—in addition to the Cooper NGCC in the preferred plan.[30] We take issue with this analysis as it relies on outdated costs estimates for capital costs of new gas plants. As with the IRP modeling, EKPC assumed $1,544 per kW for NGCC plants.[31] But recent IRP's have modeled capital costs around $2,000 per kW for new NGCC plants.[32] The rise in costs have

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[28] "Active" projects refer to those that are currently in PJM's interconnection queue that have not been withdrawn or otherwise removed. This includes projects that are generally active, as well as those already in-service, under construction, or in the engineering and procurement phase. Source: PJM. Accessed September 2, 2025. "Serial Service Request Status." Available at: https://www.pjm.com/planning/service-requests/serial-service-request-status.
[29] EIA-860M, July 2025. Available at https://www.eia.gov/electricity/data/eia860m/.
[30] Company Response to Staff 1-1.
[31] Company Response to Staff 2-23. See Attachment "Staff_2-23_-_Table_8-2_(Revised)".
[32] Case No. 2025-00045, KU/LG&E response to PSC-3 Question No. 8(b). See Attachment 1, p.6; Dominion 2025 IRP, Table 12, available at: https://www.dominionenergy.com/-/media/content/about/our-company/irp/pdfs/desc-integrated-resource-plan-2025.pdf.

been largely driven by supply chain constraints related to gas turbines, where increased demand and limited manufacturing capacity have not only raised costs but also caused extended lead times.[33] EKPC has acknowledged this recent trend in gas resource costs, stating that "[i]n recent years the gas turbine costs have increased and the market appears to be continuing on that same trend."[34] The 1 GW load analysis is therefore clearly too favorable to gas installations. For this primary reason, one should not conclude that more new gas is the least-cost option if there is a new large load need on the system. If such a new load arises, then EKPC should update its modeling using up-to-date gas capital costs that reflect recent trends to accurately determine what is the least-cost alternative.

Finally, we caution that if large potential new loads, such as prospective data centers, are included in future load forecasts, the Company should be assess the likelihood of that load materializing to help the Commission and stakeholders evaluate the potential need for new generation resources.[35] As data centers proliferate nationally, and may begin to appear in Kentucky, EKPC should keep the Commission and stakeholders apprised of developments that affect the level of expected large load customers in its service territory.

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[33] Shenk, M. July 2025. "Rush for US gas plants drives up costs, lead times." Reuters, available at: https://www.reuters.com/business/energy/rush-us-gas-plants-drives-up-costs-lead-times-2025-07-21/; Anderson, J. May 2025. "US gas-fired turbine wait times as much as seven years; costs up sharply." *S&P Global*, available at: https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

[34] Company Response to Sierra Club 2-12.

[35] See KU/LG&E 2024 IRP, Volume III, Table 10, available at: https://psc.ky.gov/pscecf/2024-00326/rick.lovekamp%40lge-ku.com/10182024014139/08-LGE_KU_2024_IRP_Volume_III.pdf.

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Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of Sierra Club's Comments on East Kentucky Power Cooperative, Inc.'s 2025 Integrated Resource Plan in this action is being electronically transmitted to the Commission on September 11, 2025, and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

/s/ Joe F. Childers
JOE F. CHILDERS