COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2024 JOINT INTEGRATED RESOURCE PLAN OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY	CASE NO. 2024-00326

SUPPLEMENTAL POST-HEARING COMMENTS OF KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY, METROPOLITAN HOUSING COALITION, AND MOUNTAIN ASSOCIATION TO LOUISVILLE GAS & ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

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INTRODUCTION

Joint Intervenors provide these supplemental comments in light of additional facts and arguments brought forth in LG&E-KU's Responsive Comment and through cross-examination from the administrative hearing. As in the 2021 IRP, the Companies' engagement in this IRP review proceeding appears trained on finding the regulatory minimum. Joint Intervenors respectfully submit this comment to reiterate that Integrated Resource Planning is essential to effective utility management and is one of the most critical tools at the Commission's disposal to achieve its mandate to enforce the requirements of KRS Chapter 278, including the requirement that utilities charge "fair, just and reasonable" rates and furnish "adequate, efficient and reasonable service."[1] As such, Joint Intervenors' position remains unwavering: We urge the Companies to treat the integrated resource planning process as real-world planning exercises that transparently report a utilities' long-term resource evaluation and plan in the face of unavoidable uncertainty and subjectivity.

DISCUSSION

I. No Party Disputes that Integrated Resource Planning Should be a Non-adversarial and Collaborative Effort.

A. History and Background

In the 2021 IRP review proceeding, the Companies delved into the history of Kentucky's IRP regulation, much as they have done in this proceeding. In both cases, the Companies' apparent purpose has been to narrowly interpret regulatory requirements, to limit the Commission's authority vis a vis long-range resource planning, and to reject the notion that integrated resource planning has real-world implications.

[1] KRS 278.030(1)(2).

While doing so, the Companies shy away from acknowledging that LG&E's poor planning in the late 1970s and 80s was the catalyst for the IRP regulation in the first place.[2] Joint Intervenors respectfully remind the Companies and the Commission of LG&E's role in the inception of the IRP regulation, and offer that the lessons learned should not be forgotten—lest those mistakes be repeated.

In October 1978, LG&E obtained a certificate for two 495 MW-nameplate coal-fired generating units in Trimble County at an estimated cost of $542.6 million, or roughly $548,080/MW, with expected operational dates in 1983 (Unit 1) and 1985 (Unit 2).[3] However, it was not long before LG&E cancelled one of the two units, delayed the remaining unit until 1988, and increased the cost estimate for that single unit to $737.9 million.

With the prospect of years more delay and ballooning costs, several parties in LG&E's then-recent rate case "challenged continuation of a cash return on LG&E's construction work in progress balance . . . ."[4] That, in turn, prompted LG&E to restudy the need for even a single Trimble County unit through a new capacity expansion study.[5]

Meaning, six years *after* issuance of the certificate, LG&E was back to the drawing board, with millions already sunk and more at risk. At best, customers were looking at a half-sized project with nearly tripled costs on a per megawatt basis ($1,490,707/MW), and the need for the project—even at half-size—remained unclear.

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[2] Case No. 9243,Order, *An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1*(Oct. 14, 1985) ("Trimble County Case").

[3] *Id.* at 1.

[4] *Id.* at 2.

[5] *Id.* at 1–2.

Called to address LG&E's situation, the Commission ordered a further three-year construction delay for the single unit.[6]

But the Commission did not stop there. The Commission lamented the excess of capacity in the state, reflecting utilities' failures to plan better than their own self-interest required, and resolved to systematically address electric utilities' generation planning:

> The Commission intends, as soon as possible, to develop, analyze, and implement statewide options that will be beneficial to Kentucky ratepayers. This will be accomplished through a cooperative effort with all interested parties, including the utilities, and through the services of an independent consultant. These options include targeted conservation, aggressive load management, additional bilateral exchanges among the state's utility companies, marketing the state's generation capacity to other regions of the country, joint ownership of generating capacity, installing alternative types of capacity, refurbishing older generating units, and establishing a centrally dispatched pooling arrangement.[7]

The Commission was unmistakably concerned about poor generation planning generally, and in LG&E's particular case.[8] LG&E became the spark igniting the Commission's generation planning investigation docket.[9]

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[6] *Id*. at 24–25.

[7] *Id.* at 23 ("A total of 51 plans are used in the S&W study originally filed. In order to compare the various plans, the present worth revenue requirements associated with each plan are calculated."); *see also* Case No. 8924, Order, *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company* at 33 (May 16, 1984).

[8] *See*, e.g., Case No. 8924, Order, *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company* at 33 (May 16, 1984) (announcing in LG&E rate case order, that "[t]he Commission intends to move forward with Case No. 8666, *Statewide Planning for the Efficient Provisions of Electric Generation and Transmission Facilities*, to review not only the need for Trimble County, but also the future generation needs and construction plans of other electric utilities regulations by this Commission. Case No. 8666 will provide the opportunity for LG&E and other interested parties to present evidence of the need, or lack thereof, for Trimble County. The options to be considered will include, but not necessarily be limited to, further deferrals of Trimble County, cancellation of Trimble County, the installation of alternative types of generating units, purchasing capacity, refurbishing older generating units, joint ownership of generation capacity, power pooling, and other options. The Commission will consider these same options when reviewing the generation requirements and construction plans of all electric utilities.").

[9] Case No. 308, Order, *An Inquiry into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting Those Needs, Admin*., at 1 (Oct. 9, 1986) (noting recent orders indicating intention to establish a docket to review plans to meet electricity needs, and citing only the Oct. 14, 1985 Order in Case No. 9243, focuses on the need for Trimble County Unit No. 1).

B. The Companies' efforts to limit the IRP review process do disappoint.

Joint Intervenors continue to agree with LG&E-KU that the IRP process is intended to be a "constructive, non-adversarial, and informal exchange."[10] Despite sharing this view, the Companies disappointingly behaved as staunch opponents to robust long-range planning review by declining to engage with stakeholders while developing the IRP, moving to cancel the hearing, and in seeking to limit the scope of the IRP throughout its comments excluding topics related to the immediate collateral effects of the Companies' planning: new capital investment proposals for generation, transmission, and distribution assets, and substantial increases to annual revenue requirements.

In their broadest swipe to diminish Commission review of integrated resource planning, the Companies sought to cancel the scheduled hearing in this proceeding.[11] Attempting to avoid including a hearing as part of the stakeholder and Commission IRP review process, the Companies argued that a hearing would be (1) inconsistent with the IRP regulation itself (807 KAR 5:058) and therefore outside the Commission's authority, and (2) "administratively inefficient" given the hearing already scheduled in the Companies' pending CPCN proceeding and the anticipated hearing in their forthcoming base rate applications.[12]

As the Commission explained in its Order denying the Companies' request, neither the language of the regulation nor the circumstances under which the regulation

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[10] Companies' March 28, 2025 Resp. to Intervenor Comments at 8 ("Companies Resp. to Intervenor Comments") ; Admin Case No. 308, Order at 13 (Aug. 8, 1990) ("The Commission believes an informal proceeding, where parties may exchange information and ideas in a less adversarial manner, may better serve the interests of the parties and the resource planning process.").

[11] Companies' March 28, 2025 Motion to Amend Procedural Schedule.

[12] *Id.* at 1.

was adopted indicate an intent to limit the Commission's statutory authority.[13] In fact, the opposite is true: the Commission's regulatory mandate is very clear – to regulate utilities and enforce the provisions of KRS Chapter 278 by adopting "reasonable regulations [] and investigate the methods and practices of utilities."[14] Despite the Companies' suggestions to the contrary, there is no limiting clause to the Commission's authority to review utilities' long-range resource planning. Joint Intervenors continue to support the Commission's broad authority to investigate utilities as it sees fit.

In their response to intervenor comments, the Companies' also complain of "misstatements of fact" and "misrepresentations" made by intervening parties.[15] Responses to Joint Intervenors Initial Comment and the AEC Report, however, are almost entirely differences of opinion.[16] The Companies' resistance to feedback does not render intervenor comments either erroneous nor dispensable. To the contrary, the robust engagement of numerous intervenor groups offering their unique perspectives and expertise to assist the Companies in improving their planning process is the exact constructive exchange of ideas that the IRP regulation seeks to facilitate. Rather than take offense from critiques and recommendations for improvement that intervening parties have offered, the Companies might view this process as an opportunity to consider their planning process from the perspective of stakeholders with a shared goal of advancing affordable and reliable service.

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[13] May 5, 2025 Order at 6–7.

[14] May 5, 2025 Order at 4; KRS 278.040(1)-(3).

[15] Companies' Resp. to Intervenor Comments at 7–8.

[16] Joint Intervenors respond to each point raised by the Appendix to the Companies' March 28, 2025 Response at the end of this document.

C. The Companies' can improve their IRP process by proactively increasing transparency and accessibility beyond baseline filing requirements.

The Companies' response comment paid attention to AEC Report comments regarding transparency of IRP reporting, with the Companies particularly bristling at the suggestion that the IRP could have been more transparent and accessible.[17] Specifically, the Companies complain that the workpapers were provided as promptly and appropriately as possible, access to confidential information was appropriately handled, and the IRP highlights were provided in an easily digestible summary and presentation.[18] Respectfully, there are finer points being missed by the Companies.

First, there is a difference between information available only through workpapers and information available on the face of the IRP itself. For example, when the public IRP does not report the public PVRR results of each modeling run, it is lacking in transparency in an important respect. Portfolio PVRRs "on the whole . . . were not presented in the IRP report at all."[19] The fact that PVRR data can be gleaned *if* a stakeholder becomes a party or otherwise obtains workpaper access does not improve the transparency of the IRP. The fact that the Commission reasonably accommodated an alternative filing approach does not improve the transparency of the IRP. Only LG&E-KU can increase the transparency of the IRP itself by, for example, providing more quantitative financial reporting of various modeling runs used to inform the Companies' decision making and resource preferences.

Second, and relatedly, if a stakeholder needs to pursue data requests or dig through workpapers to identify portfolio PVRRs, or other important details that could

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[17] *Id.* at 8.

[18] Companies' Resp. to Intervenor Comments at 8–9.

[19] Attach. JI-1, AEC White Paper, *LG&E-KU's 2024 Integrated Resource Plan: An Assessment*, at 56 ("AEC Report").

have been publicly reported on the face of the IRP, that makes the IRP less accessible to non-experts and non-parties. However many pages, sections, or volumes constitute the IRP,[20] a transparent and accessible IRP should provide the forecasted revenue requirement impacts of modeled portfolios, and other critical planning details. The Companies have not disputed the relevance or critical character of portfolio PVRRs in an IRP. To the contrary, the Companies insist that portfolio PVRR estimates are so critical that they should be the only financial metric that stakeholders concern themselves with in IRP planning.

Third, of course, accessing confidential information reasonably calls for executing non-disclosure agreements and Joint Intervenors never intended to suggest otherwise.[21] Still, the scope of confidentiality designations truly matters to the transparency of an IRP itself and the IRP review proceeding. It matters to parties insofar as utilities routinely refuse to enter into an NDA unless and until a party is granted intervenor status. If redactions are overbroad, at the outset or throughout the proceeding, party access to that information is needlessly delayed and public access is entirely foreclosed.

And lastly, while it is true that the Attorney General as an intervenor in this matter represents the interests of LG&E-KU customers, individuals without intervenor status can only participate by reviewing publicly posted documents and by submitting public comments. Without a complete and accessible public filing, stakeholders are prevented from fully participating in the Companies' planning process. Joint Intervenors reiterate

[20] *Cf.* Companies' Resp. to Intervenor Comments at 10 (disputing reasonable basis for AEC observation that important modeling results were not presented in the IRP itself by noting first that the Companies "provided a separate Executive Summary document for the first time in an IRP proceeding to present the IRP highlights in an easily digestible format and length. The IRP itself contained a summary section in addition to the three-volume full IRP documentation.").

[21] Companies' Resp. to Intervenor Comments at 9–10.

that intervention is a substantial hurdle for participation. Members of the public should not be required to hire legal representation, obtain intervenor status, sign confidentiality agreements, and have an advanced degree to understand the Companies' voluminous and opaquely presented results. Non-intervenors are not able to access the full record, and as a result, the Companies' IRP is not the transparent and public process it is intended to be. The high barriers to participation prevent meaningful stakeholder engagement and undoubtedly limits access and delays review of the Companies' report. Joint Intervenors respectfully suggest that Companies lower the barrier for entry, making their IRP accessible to all of its stakeholders.

D. The Companies' IRP process could be improved with early and substantive stakeholder engagement.

In practice, an IRP's most basic function is to provide a utility's resource planners with a framework for evaluating plausible futures for its electric system through input from stakeholders and regulators.[22] An IRP is intended to be a collaborative, symbiotic process in which a utility engages with stakeholders and the Commission to determine a least-cost portfolio by providing information regarding electric system demand, reliability, costs, risks, and uncertainties, and other important issues that may affect the utility's customers.[23] Rather than embrace this process, LG&E-KU have taken the position that the review proceeding itself is the stakeholder process – no further inclusion, collaboration, or engagement needed.

Joint Intervenors respectfully repeat that now is not the time to reduce regulatory oversight or public participation in utilities' resource planning processes. As utilities

[22] Synapse, *Best Practices in an IRP* (Dec. 4, 2024) ("Synapse Report"), https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf).

[23] Synapse Report at 1.

scramble to prepare for unprecedented and uncertain load growth, the public is entitled more than ever to ensure the Companies' long-range resource planning provides for just and reasonable rates. LG&E-KU's customers deserve a transparent and comprehensive look at the Companies' plans to meet the challenges that the next decade holds for the electric sector, and a robust IRP process is the appropriate vehicle to accomplish that goal. Through purposeful engagement with stakeholders, LG&E-KU can better advance the public interest in providing reasonable and adequate service at affordable rates.

As recommended by Joint Intervenors in the last iteration of the Companies IRP[24] and reiterated in Joint Intervenors initial comments in this proceeding, the Companies' integrated resource planning would benefit from early, ongoing, and substantive stakeholder engagement.[25] As Joint Intervenors' highlighted in 2021, pre-filing engagement with stakeholders has materially improved the planning processes of other utilities, lessened the disputed issues in IRP proceedings, and allowed both utilities and stakeholders to better understand each other's perspectives and concerns.[26] LG&E-KU are correct that the IRP regulation does not require utilities to facilitate stakeholder processes, but that alone is not reason enough to ignore the benefits that increased stakeholder engagement can provide to the Companies' iterative planning. A truly transparent process engages with stakeholders throughout - before modeling begins to propose scenarios and inputs, during modeling to provide input on results, and after the draft plan is released to provide input on how results were used to create an action

[24] Case No. 2021-00393, *Joint Intervenors' Supplemental Comment on Louisville Gas and Elec. Co. and Ky Util. Co.'s Joint 2021 Integrated Resource Plan, at 13* (Aug. 22, 2022).
[25] *Id*. at 13.
[26] *Id*. at 13–14.

plan.[27] A pre-filing stakeholder process not only aligns with the informal, constructive, and non-adversarial process that the Companies' seek, but could also help to alleviate the Companies' workload by narrowing the issues to consider in addressing stakeholder input. As discussed in the AEC white paper attached to Joint Intervenors' initial comments in this proceeding, it is to the benefit of all involved for LG&E-KU to incorporate a stakeholder process as a key element in the development of their IRP by seeking meaningful feedback from Commission staff and stakeholders who are directly impacted by the resulting resource decisions.[28] Accordingly, Joint Intervenors urge LG&E-KU to more fully engage with stakeholders in pursuit of a comprehensive and transparent plan that is reflective of real-world impacts to its customers.

II. Load Forecast

A. Demand-Side Management

Instead of responding to the AEC Report critique that the Companies did not adequately model DSM program savings past 2030, the Companies miss the point. The AEC Report made various observations about how DSM resources were—and were not—evaluated as part of the 2024 IRP, including that the Companies' load forecast assumes declining annual energy savings beginning in 2030.[29] Using a workpaper supplied by LG&E/KU, Figure 6 of the AEC Report graphs the declining annual energy savings assumptions in the various IRP forecasts. The Companies have not disputed the accuracy of Figure 6 or their underlying workpaper.

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[27] Synapse Report at 10.
[28] AEC Report, at 54–55.
[29] AEC Report at 17.

Instead, the Companies pivot to discussing cumulative energy savings after 2030.[30] There is no disagreement with respect to cumulative energy savings.[31] But there also is no misstatement of facts.[32] Both are true: annual energy savings assumptions as a percentage of sales decline in all load forecasts after 2030; and cumulative energy savings continue to grow year-to-year.

Respectfully, had specific DSM-EE program assumptions after 2030 been stated on the face of the IRP with some specificity, back-and-forth would be unnecessary. If it existed, the Companies could simply identify where the IRP provides annual program budget and savings assumptions for years after 2030, disaggregated from other non-program sources of energy savings. But those details were not shared in the IRP.[33] Nor does the IRP spell out what the assumptions for "new programs beyond 2030" would be, how savings potential was determined, how budget levels change year-to-year, or the estimated savings attributable to program activities after 2030.

The Companies' response to Joint Intervenors' Comment continued to opine that it is "unsurprising that there is not a significant amount of additional cost-effective DSM-EE in IRP modeling" in light of their recent DSM-EE Plan approval and potential new large load customers that may (or may not) materialize.[34] This has no technical support and makes no sense. Beyond limited demand response expansion, the

[30] Companies' Resp. to Intervenor Comments at 2.

[31] The strength of the cumulative energy savings trend reflects the savings-life of efficiency improvements and energy waste reduction.

[32] *Contra;* Companies' Resp. to Intervenor Comments at 2.

[33] LG&E-KU have provided the most specific citations available from the IRP in their response to intervenor comments which convey mere assertions that a forecast included "new programs beyond 2030" and existing programs are "assumed to continue" through 2039. Companies' Resp. to Intervenor Comments at 20, note 3.

[34] Companies' Resp. to Intervenor Comments at 14.

Companies did not model DSM-EE program savings potential on equal footing with their more costly supply-side counterparts.

Additionally, the Companies do not have a credible assessment of the cost-effective savings potential in their territory. The same was true in the Companies' 2021 IRP, when despite simultaneously pursuing plans behind-the-scenes to develop billion-dollar gas plant proposals, the Companies had not updated their 2016 and 2017 vintage potential studies; it was true when the Companies proposed their 2024-2030 DSM-EE Plan; and it is true in the 2024 IRP. That's two IRP planning cycles and the development of a seven-year DSM-EE portfolio without a reasonably updated picture of energy savings potential for one million Kentucky electric customers.

Over that same period of time, the Companies nevertheless found the wherewithal to develop multiple plans extensively evaluating supply-side resource alternatives, each benefiting from updated cost and other data inputs. As a result of those re-analyses, the Companies continue to identify and propose new supply-side resource investments, and the Companies do so without regard for how recent their last CPCN approval was.[35] Demand-side management potential should get that same level of updating and reanalysis.

B. Distributed Resources

Similarly, the Companies failed to adequately account for the possibility of distributed resources, including both demand response and distributed energy resources such as solar and batteries.

[35] *Cf.* Companies' Resp. to JI 1.3 (suggesting it would be premature to update DSM-EE plan over the next three years because seven-year plan was approved in Case No. 2022-00402).

1. <u>The Company failed to adequately include DR expansion.</u>

In initial comments and the attached White Paper, Joint Intervenors made extensive critique of the Companies' demand response programs, in particular for large loads (see below for more on the large load projections specifically). The Companies' only response is that the "IRP did analyze certain DR program measures, which are included in the IRP Recommended Resource Plan."[36] There is no discussion of how or where the specific critiques of the Joint Intervenors are addressed.

With regard to existing and evaluated demand response programs, the AEC White Paper acknowledges that demand response was properly included demand response programs for model selection in making resource decisions. However, it appears that as with other DSM programs "they have failed to reexamine and expand the DSM resources available as modeling sensitivities or for selection in their optimization modeling."[37] As confirmed at hearing, no updated potential study was done or contemplated prior to the IRP, therefore, the DR resources offered to the model were based on a potential study from 2021, with outdated avoided costs.[38] Furthermore, the Companies put artificial, hardcoded constraints on renewables, including potential renewable demand response programs, as part of modeling, limiting their potential.[39] The Companies offer no rebuttal.

Furthermore, in initial comments, Joint Intervenors stated that "the Companies fail to address the possibility of new large load additions participating in demand response or curtailable service ride programs, potentially allowing a significant shaving

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[36] Companies' Resp. to Intervenor Comments, Appendix at 4.
[37] AEC Report at 17.
[38] May 14 HVT at 2:25:30 to 2:28:45 p.m.
[39] AEC Report at 26.

of the peaks currently projected from these sources."[40] The policy brief from American Center for an Energy Efficient Economy (ACEEE), offered as an attachment, provides a potential roadmap for just demand response from data centers,[41] yet similarly went unacknowledged. Finally, the EPRI report offered as support for the Companies' load projections,[42] suggests as actions to support data center growth that utilities should work to "[i]mprove data center operational efficiency and flexibility" and "[i]ncrease collaboration through a shared energy economy model for sustainable data centers."[43]

2. The Company fails to seriously engage Joint Intervenors' critique of their distributed energy resource (DER) forecast.

As stated in Joint Intervenors' initial comments, "The Companies acknowledge in passing several times the influence their own decisions may have on projected load growth, but fail to seriously grapple with the alternatives and present an actual summary of LG&E-KU's plans or steps to be taken. Given the significant load growth projections discussed above, the Companies should have at least seriously evaluated the possibility of mitigating or offsetting load growth through implementation of cost-effective measures."[44] This critique goes un-addressed in Companies' reply comments. The only response regarding distributed solar is the conclusory statement that "Contrary to AEC's assertions, the Companies' distributed solar forecasts are well documented and reasonable," with a citation pointing back to Volume I Section 7.(7).(b).7 of the IRP.

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[40] JI Initial Comments at 32.

[41] *Id.* at 32–33; Nora Wang Esram et al., *Turning Data Centers into Grid and Regional Assets: Considerations and Recommendations for the Federal Government, State Policymakers, and Utility Regulators, ACEEE Policy Brief* (Oct. 17, 2024). https://www.aceee.org/policy-brief/2024/10/turning-data-centers-grid-and-regional-assets-considerations.

[42] Vol. I at 5–16, n. 23.

[43] EPRI, *Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption,* at 21–23 (May 28, 2024). https://www.epri.com/research/products/3002028905.

[44] Initial Comments at 27–28 (footnote omitted).

Joint Intervenors offer significant critique of this very section, however. For instance, the difference between the high solar forecast and the mid and low solar forecasts is apparently based on a decision Companies may make as to whether to end offering net metering past 1% of the previous year's peak load.[45] Even at that, the Companies fail to adequately explain the significant drop-off in additions of behind-the-meter solar even in the high solar forecast, and also fail to demonstrate why additional growth to levels seen in other jurisdictions such as Vermont and Massachussetts.[46] The Companies also fail to address the suggested strategies for potentially increasing distributed solar penetration.[47]

C. "Economic Development" load

Contrary to the Companies' assertion that their Mid and High load forecasts have "ample support for their data center and other economic development load projections,"[48] Joint Intervenors respectfully put forth that the Companies have not provided sufficient evidence to justify the levels of load assumed.

While the Companies claim their assumptions appropriately reflect "information available at the time,"[49] there is little to no documentation of the "information" they rely on. Instead, the Companies subjectively categorize potential projects into "stages" based on private conversations with project developers and perceived likelihoods of project completion. Without providing any visibility into who or what the projects in various stages of development are, the Companies rely on these closed-door conversations to justify their load growth projections. The Companies' failure to

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[45] JI Initial Comments at 30.
[46] *Id.* at 31.
[47] *Id.*
[48] Companies' Resp. to Intervenor Comments at 11.
[49] Companies' Resp. to Intervenor Comments, Appendix at 7.

transparently report the basis for their long-term resource planning assumptions in the face of unavoidable uncertainty and subjectivity engenders distrust of their load growth projections.

Second, the Companies assert that accounting for only projects that have been announced or under contract would be unreasonable because, for example, the Camp Ground Road data center was not yet announced when the IRP was filed.[50] Inversely, the Companies explain that planning for all possible data center projects in their economic development queue would be equally unreasonable.[51] This is a misconception of the Companies' own creation. Joint Intervenors do not suggest that the Companies must plan for either all or nothing. To be clear, verifiable incoming loads *should* be included in the Companies' planning. Joint Intervenors only suggest that the Companies put forth clear evidence and justification for their assumptions regarding new large load customers. As recommended by AEC in their white paper attached to Joint Intervenors' initial comments: "LG&E-KU should provide documentation and clear rationale supporting its high expectations for data centers locating in the territory over the next five years."[52] The Companies' assumptions regarding potential data center load growth *may* be reasonable, but that cannot be determined unless and until verifiable information is made available for scrutiny.

There is no dispute that planning to serve incoming loads is an important aspect of the Companies' obligation to provide adequate service to both existing and incoming customers.[53] However, it would be imprudent to assume an obligation to serve *all* future

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[50] *Id.* at 6.
[51] *Id*.
[52] AEC Report at 21.
[53] Companies' Resp. to Intervenor Comments at 11; KRS 278.010(14).

customers – regardless of how speculative or unlikely they are to materialize in the Companies' service territory. As described in detail in Joint Intervenors' initial comments, [54] exaggerated load growth assumptions pose significant affordability and reliability risks to LG&E-KU customers that is incompatible with least-cost planning. Simply speaking, the risks to ratepayers from an unsupported and inaccurate load forecast is excessively high when the Companies' purport to rely on projections as a basis to support their resource decisions and rate calculations.

The risks of overgeneration resulting from poor planning are well-known, with cost impacts that can last for decades.[55] Data center load growth further amplifies this risk due to the unresolved nature of potentially incoming demand. Inaccurate energy forecasts pose a high risk, often leaving residential customers with skyrocketing electric bills,[56] a trend expected to continue alongside the growth of data centers.[57] Where the Companies' resource planning process is aimed at providing safe, reliable, and least-cost service, LG&E-KU must ensure that its existing ratepayers are not stuck with the burden of paying increased rates for projects that fail to materialize. Without real, tangible evidence of potential economic growth, the risks to current ratepayers is too high to accept. In the absence of concrete information confirming incoming load, the

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[54] See JI Initial Comments, Section 3(b) at 22-27.

[55] *See*, *e.g.*, Trimble County Case.

[56] *See e.g.*, Evan Halper et al., *As data centers for AI strain the power grid, bills rise for everyday customers*, Wash. Post (Nov. 1, 2024), https://www.washingtonpost.com/business/2024/11/01/ai-data-centers-electricity-bills-google-amazon/.

[57] Robert Walton, *AI, data center load could drive 'extraordinary' rise in US electricity bills: Bain analyst*, Utility Dive (Oct. 23, 2024), https://www.utilitydive.com/news/data-center-load-growth-us-electricity-bills-bain/730691/; Khari Johnson, *Crackdown on power-guzzling data centers may soon come in California*, S.F. Chron. (Feb. 18, 2025) https://www.sfchronicle.com/bayarea/article/crackdown-power-guzzling-data-centers-soon-come-20173899.php; Stanley Dunlap, *State senator pushes bill to protect Georgia Power customers from rate hikes fueled by data centers*, WABE (Feb. 10, 2025) (California and Georgia both are looking to pass bills to protect ratepayers from data center harms) https://www.wabe.org/state-senator-pushes-bill-to-protect-georgia-power-customers-from-rate-hikes-fueled-by-data-centers/.

Companies' have provided an insufficient basis for their 11 to 20 percent forecasted increase that is driving their recommendation for new capacity investments and lead to significant costs to customers.[58]

III. Resource Assessment and Acquisition Plan

A. Recommended Plan

1. The Recommended Plan did not result from the modeling

Although the Companies make a respectable effort to surround their Recommended Plan with modeling data, it bears repeating that the Companies' Recommended Resource Plan did not result from the Companies' resource expansion modeling. The AEC Report addresses the process for selection of the Recommended Plan at section D, pages 46-53, including recommended practices to improve the Companies' next planning efforts. Notably, the Companies have not disputed the discussion of PVRR results raised therein, which raised significant questions about the credibility of the modeled PVRR estimates.

It is unreasonable for an IRP to rely exclusively on modeled PVRR estimates, but not disclose those PVRR estimates on its face and not answer significant doubts about the validity of those estimates. The criteria used to judge resource alternatives should be plainly presented.

Additionally, it is unreasonable to make resource decisions solely on the basis of estimated PVRRs. Everyone agrees that PVRRs are an important metric, but it would be a mistake to treat PVRRs as the only metric that matters in resource planning.

[58] AEC Report, Attach. JI-1 at 23.

2. The Commission should require clear accounting for resource decisions made only to accommodate specific new large loads.

As the Companies acknowledge, and discussed above, the load forecast in this IRP is unprecedented. Given the unprecedented nature of this load forecast, as well as the uncertainty surrounding many aspects of it, the Commission should require a clear accounting of the resource decisions made specifically to accommodate this new load and ensure financial accounting that protects existing ratepayers.

As is discussed above, the Companies' load forecast is unprecedented and unsupported. Yet, in reliance largely on that forecast, the Companies put forward a recommended plan that includes a new battery energy storage system, two new natural gas combined cycles, and significant investment in new environmental controls at existing coal plants, including a unit for which the Companies claimed additional investments would constitute a "regrettable mistake" "almost certain[ ] [to] result in only a handful of years of additional service life" only a year prior to the filing of the IRP.[59]

While the price tag for those investments is a massive $3.7 billion, at hearing it was made clear this wasn't even the half of the Companies' planned capital investments. Over the next 4 years alone, the Companies expect to make roughly $10 billion in capital investments, including almost $9.5 billion in electric generation, transmission, and distribution.[60] It is unclear what portion of that investment plan is attributable to data centers, but it represents a significant potential increase for Companies with a current rate base of $12.4 billion.[61]

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[59] Case No. 2023-00122, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Elec. Co. for Approval of Fossil Fuel-Fired Generating Unit Retirements*; *see also* Case No. 2022-00402, *Post-Hearing Brief of Ky. Util. Co. and Louisville Gas and Elec. Co.,* at 1 (Sep. 22, 2023).

[60] JI Hearing Ex. 1 at 21; May 13 HVT at 11:16:15 to 11:17:07 a.m.

[61] JI Hearing Ex. 1 at 16; May 13 HVT at 11:13:00 to 11:14:15 a.m.

What did become absolutely certain from the hearing, however, is that ***but for*** the projected load growth associated with data centers, the Companies would not only not need the new resources in the recommended plan, they would in fact have excess capacity of 974 MW by 2039, or roughly a 46% reserve margin.[62] Depending on circumstances, absent some other driver for load growth, not only would new resources not be necessary it would even make sense to potentially retire uneconomic resources previously proposed for retirement such as Ghent 2 and Brown 3.[63]

Given, then, that at a minimum the new resources in the recommended plan would not be necessary but for the data center load growth, and the disproportionate impact this may have on the Companies' overall capital expenditures and rate base compared to current rate base before such data centers, the Commission should at a minimum require a more clear accounting of exactly what investments are being driven by speculative new customers ***now*** so that it can be considered later when deciding whether and what increases to existing ratepayers are appropriate

B. Transmission & Distribution

Following the hearing and the Companies' most recent data responses, Joint Intervenors offer six additional comments on transmission and distribution in long-range resource planning.[64]

One, distribution and transmission planning has critical implications for least-cost and reliable electric service, and must be seriously accounted for as part of Integrated Resource Planning.[65] With respect to affordability, the transmission and

[62] May 13 HVT at 11:35:20 to 11:43:30 a.m.; Vol. III, Resources Assessment at 23.

[63] May 13 HVT at 11:35:20 to 11:43:30 a.m.

[64] Joint Intervenors' Initial Comment, Section 5 at pages 40–51, provides additional feedback on the transmission and distribution planning aspects of the 2024 IRP.

[65] 807 KAR 5:058, Sec. 8(2)(a) (Resource Assessment and Acquisition Plan "shall describe and discuss all options considered for inclusion in the plan including: (a) Improvements to and more efficient

distribution plant expenses make up a significant share of the Companies' revenue requirements.[66] In addition to being a large contributor to base rates, the Companies highlight capital investment in distribution and transmission assets as major drivers of their recently-filed rate increase request.[67] Like generation assets, new distribution and transmission assets are long-term investments, with expected useful lives that span decades.[68] These are significant long-term investments that should be carefully considered in long-term resource planning.

With respect to reliability, customers' lived experience of reliability and resilience generally has more to do with distribution and transmission resources than generation resources. For example, the failure of a single oil circuit breaker once caused the Companies to interrupt over 6,600 customers for multiple hours,[69] and it is widely accepted that the major cause of customer outages is the vulnerability of transmission and distribution assets to severe weather, equipment failure, and human error. That is

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utilization of existing utility generation, **transmission, and distribution facilities**") (emphasis added); Case No. 2022-00402, *Elec. Joint Application of Ky. Util. Co. and Louisville Gas and Elec. Co. for Certificates of Pub. Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Order at 95 (Nov. 6, 2023) ("[T]he Commission exhorts LG&E/KU to study the value and opportunities that transmission (regional and interregional) and imports provide in their next IRP. In their past IRPs, any serious consideration or discussion of transmission has been notably absent. Further failure to discuss these options in future proceedings may result in the Commission's own investigation into LG&E/KU's processes in this regard.").

[66] *E.g.*, 2025-00113 & 2025-00114, *Electronic Applications of Kentucky Util. Co. and Louisville Gas & Elec. Co. for an Adjustment of Rates and Approval of Certain Regulatory and Accounting Treatment*, Vol. 10, Tab 55, Schedule B-2 (providing plant in service by major property grouping in base and forecasted test period) .

[67] *E.g.*, Case Nos. 2025-00113 & 2025-00114, Direct Testimony of Robert M. Conroy at 3-4 (identifying distribution and transmission investments as a primary driver of requested revenue requirement increases, with plans to spend over $1 billion on transmission and distribution assets in the coming years); Case Nos. 2025-00113 & 2025-00114, Application at para. 15 (identifying distribution and transmission as the first two among five primary drivers of the Companies' proposed increase in capitalization).

[68] *E.g.*, Case Nos. 2025-00113 & -00114, Direct Testimony of Elizabeth McFarland at 12, 14 (sixty year service lives of wood structures and the "significantly longer life expectancy of steel structures" in the Companies' transmission system)

[69] *Id.* at 15 (supporting proposal to consider oil circuit breakers within or beyond 10 years of their 60-year service life with the reminder that "in 2020, a 48 year-old oil breaker failed in the urban Lexington area resulting in a bus lockout and interrupting over 6,600 customers for multiple hours").

why, for example, respected experts panned[70]—and FERC unanimously rejected[71]—past attempts to claim "fuel security" meaningfully threatens grid reliability and resilience.[72] For all the Companies' attention to generation adequacy relative to peak demand, it is easy to miss that energy delivery failures on the distribution and transmission systems are larger customer outage drivers than generation resource adequacy.

Two, distribution and transmission planning materially impacts generation resource potential. That is true with respect to utility-scale generation, which can be most affordably sited at existing transmission system interconnection points; and true with respect to distributed energy resources that can materially impact distribution circuit capacity. But it does not appear that the Companies conduct integrated planning of distribution and transmission assets or distributed energy resource potential in their triennial supply-side portfolio modeling.[73]

Three, the Companies' transmission planning and capital investments impact the rates and reliability of electric service in neighboring regions. The cost of new network transmission facilities (as needed to connect new load or new

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[70] *E.g.*, John Larsen, et. al, *Electric System Reliability: No Clear Link to Coal and Nuclear*, Rhodium Group (Oct. 23, 2017), https://rhg.com/research/electric-system-reliability-no-clear-link-to-coal-and-nuclear/; Trevor Houser, et al., *The Real Electric Reliability Crisis*, Rhodium Group (Oct. 3, 2017) (concluding, based on utility-reported data on power system failures from 2012 to 2016, that fewer than 0.00007% of nationwide customer outage hours were caused by fuel supply interruptions and generation inadequacy "accounted for less than one hundredth of one percent"). https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/

[71] FERC, Docket Nos. AD18-7-000 and RM18-1-000, Order Terminating Rulemaking Proceeding at para. 15 (Jan. 8, 2018) (accession number 20180108-3061) (unanimously holding that tariffs that do not compensate for "fuel security" attributes are just and reasonable, and finding no data to support claimed connection between fuel supply interruptions and grid resilience).

[72] Department of Energy Notice of Proposed Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (Sept. 28, 2017) (FERC Docket No. RM18-1-000).

[73] May 14 HVT at 10:58:00 a.m. to 11:00:00 (explaining that transmission is "an input to the IRP" providing estimates for specific transmission upgrades needed to support specified generation portfolio alternatives).

generation to the Companies' transmission system) are borne by the Companies as the Transmission Owner, but recovered from transmission customers pursuant to FERC-jurisdictional formula rates.[74] In addition to paying for transmission service as needed to serve their own retail load, the Companies' transmission customers include: Big Rivers Electric Corporation; East Kentucky Power Cooperative; Hoosier Energy REC, Inc.; Kentucky Municipal Power Agency; Kentucky Municipal Energy Agency; Louisville Gas & Electric Company/Kentucky Utilities Company; Owensboro Municipal Utilities; Tennessee Valley Authority.[75] That means that the quality of service and cost implications of the Companies' long-term transmission investments impacts customers across the state and region.

For these practical reasons—on top of the fact that the regulation requires their inclusion—long-range distribution and transmission planning should be a meaningful part of long-range *integrated* resource planning.

Four, the Companies have already made and are continuing to make transmission investments to serve speculative load additions, with those costs socialized to the Companies' existing retail and transmission customers. The Companies were not especially forthcoming on this point, until the hearing.

In response to a data request seeking to understand the range of possible costs associated with interconnecting new load to the Companies' transmission system, the Companies explain why costs are too project specific for the Companies to identify any

[74] May 14 HVT at 11:42:00 a.m. to 11:42:30 a.m. (confirming that costs recovered through the OATT are socialized across all transmission customers under FERC formula rates).

[75] Open Access Transmission Tariff, Attachment I (listing Network Integration Transmission Service customers); May 14 HVT at 11:30:00 a.m. to 11:31:30 a.m. (confirming current NITS customers).

range of possible costs, then seem to soften the blow with a sentence that suggests those costs would land on the Transmission Owner:

> However, it is important to note that the majority of costs associated with a new load interconnecting to the LG&E/KU transmission system are ultimately borne by the Transmission Owner if the new load comes to fruition. LG&E/KU's Allocation of Costs for End-User Interconnections can be found on OASIS[.][76]

In the Companies' Allocation of Costs for End-User Interconnections, new network facilities necessary to interconnect a new transmission customers are "allocated to the Transmission Owner **and recovered through the OATT**,"[77] which **socializes the cost** of those new network facilities across all transmission customers.[78]

The Companies are already spending money on new network facilities related to data center customers that may or may not materialize—not that you would know that on the face of the 2024 IRP. At the hearing, the Companies confirmed that projects identified in response to the Attorney General's Data Request 2-1b to serve the Camp Ground Rd project are network facilities to be paid for by all transmission customers.[79] Whatever happens, existing customers are and will continue to foot part of the bill for those and unknown other projects of similar character.

Five, while the Companies did improve their distribution and transmission reporting in the 2024 IRP, additional quantitative detail would strengthen future IRPs. For example, the Companies 2024 IRP narratively discusses interconnection capacity, but without providing quantitative detail.[80] This is in contrast to EKPC's 2025

[76] Companies' Resp. to JI 1.61.c.

[77] LG&E/KU's *Allocation of Costs for End-User Interconnections* (Version 2) at 2 (effective Feb. 1, 2022) (emphasis added).

[78] May 14 HVT at 11:42:00 a.m. to 11:42:30 a.m. (confirming that costs recovered through the OATT are socialized cross all transmission customers under FERC formula rates).

[79] May 14 HVT at 11:34:00 a.m. to 11:35:25 a.m., (McFarland Cross).

[80] 2024 IRP, Vol. III. Transmission Section at 3, (pdf 195).

IRP, which provides similarly narrative discussion and reports transmission interconnection capacity at each transmission interconnection point under various conditions.[81]

Six, particularly due to the robust interconnections between EKPC and the Companies' transmission systems, long-range planning efforts should be better coordinated in future IRPs. Although the 2024 IRP acknowledges that, because of the robust interconnections with EKPC and other neighbors, the Companies need to "coordinate with neighboring systems on both planning and operational needs,"[82] but based on the hearing, it does not appear as though there is any particular structure or regularity to such coordination, and there were no coordination efforts made specific to the development of the 2024 IRP.[83]

IV. Financial Information

The Commission's IRP regulation requires that plans:

> at a minimum, include and discuss the following financial information:
> (1) Present (base year) value of revenue requirements stated in dollar terms;
> (2) Discount rate used in present value calculations;
> (3) Nominal and real revenue requirements by year; and
> (4) Average system rates (revenues per kilowatt hour) by year.[84]

The Companies appear to have taken the minimum requirements quite literally. The *entirety* of the Companies' compliance with this section is reproduced below.

9 Financial Information

[81] Case No. 2025-00087, *Electronic 2025 Integrated Resource Plan of East Ky. Power Coop.*, 2025 IRP, tbl.6-1 at 150–152; *see also* Companies' Resp. to JI Q 3.4 (confirming accuracy of reported voltages of bidirectional interconnection points between EKPC and the Companies, and noting five interconnection points with different record ratings).

[82] 2024 IRP, Vol. III. Transmission Section at 6 (pdf 198).

[83] May 14 HVT at 10:58:00 a.m. to 11:00:00 (explaining that the role of transmission in 2024 IRP was limited to doing the transmission studies requested by the generation planning group).

[84] 807 KAR 5:058 Section 9.

> Annual revenue requirements and the present value of revenue requirements ("PVRR") are shown in Table 9-1 for the Mid energy requirements, mid gas, mid coal-to-gas ratio fuel price ("Mid Fuel") case. The discount rate used in the present value calculation is 6.56%. Annual revenue requirements include variable and fixed costs for both new and existing units and capital costs for new units.
>
> **Table 9-1: Annual Revenue Requirements (Mid Energy Requirements, Mid Fuel Case)**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Revenue Requirements ($M)	2,153	2,120	2,431	2,129	2,781	2,987	3,095	3,103	3,049	3,048	2,508	3,086	3,083	2,939	2,958
PVRR ($M; 2024 Dollars)	13,657														
Mid Energy Requirements (GWh)	32,808	32,867	33,668	34,806	36,057	38,292	40,569	41,200	41,033	40,971	40,949	41,057	40,930	40,949	40,943
cents/kWh	6.56	6.45	7.22	6.12	7.71	7.80	7.63	7.53	7.43	7.44	6.12	7.52	7.53	7.18	7.22

The Companies offer no further discussion of the financial information, nor information about any of the variety of scenarios presented in the IRP (including the high load scenario, which is closer to current Company projections[85]), the impacts or meaning of this financial information for ratepayers, or whether it meets the purpose of the IRP regulation to demonstrate "adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas…."[86]

The Companies' planning process appears more tailored to information important to utility shareholders than information important to customers. The companies made that plain at the hearing and throughout the proceeding, steadfastly refusing the idea that they should pencil out rate and customer impacts, and objecting to questions relating to specific costs to customers, or whether existing ratepayers may end up subsidizing the investments recommended in the Companies' resource plan.[87]

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[85] Case No. 2025-00045, Direct Testimony of Tim A. Jones, at 8 (Feb. 28, 2025).

[86] 807 KAR 5:058, Necessity, Function, and Conformity.

[87] *See*, *e.g.*, Resp. to JI 1-64 (objecting to a request for analysis of impacts of data center load growth on, among other things, the Companies or their customers); JI 2-4 (objecting to a request about upcoming rate cases); JI 2-31.a.-j. and i. (objecting a dozen times to requests for any information about disconnections, overdue amounts, late payments, repayment plans, and other information regarding struggles with Companies' bills); JI 2-33 (objecting to a request for information about how the Companies

At hearing, the Companies' lead witness, Lonnie E. Bellar, Executive Vice President, Engineering, Construction and Generation, PPL Services Corporation, spoke at length about planned rate base increases over the next four years, and the Companies' commitment to "delivering value for BOTH customers AND shareowners", and the importance of rate base increases projections to investors, stating the importance of such information to investors.[88] Meanwhile, when Joint Intervenors raised questions about the relative contributions of low-income ratepayers compared to large industrial customers to past due bills, and the impacts on ratepayers of such relative contributions, claiming the IRP regulation "does not say let's break this down by rate class. It does not say that we need to maximize or minimize rates for any particular customer."[89]

Joint Intervenors recommend the Commission and staff ask in the future for exactly that sort of analysis as a part of the IRP process. If a particular customer is effectively distorting the balance of overdue payments that affects a variety of analyses directly relating to the "adequate and reliable supply of electricity at the lowest possible cost *for all customers* within their service areas," particularly in an era where the Company is projecting the largest individual customer additions to its load potentially

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are helping low-income and households of color struggling with paying bills); JI 2-34 (objecting to questions about DSM charges and expenditure for low-income and communities of color); JI 2-36 (objecting to a request for information about the past due amounts); May 14 HVT at 9:29:45 to 9:37:00 a.m. (objecting three separate times to questions related to ratepayer protections related to new large loads, and questions about previous objections to these questions); 9:50:22 to 9:51:08 (objecting, and stating "the companies will respond to all those questions as they see fit in accordance with their duties with with appropriate legal parameters on those questions" in subsequent cases); 9:52:00 to 9:53:50 a.m. (objecting twice in a row to questions about existing customers subsidizing new revenue requirements for large load growth); 11:17:00 to 11:17:30 a.m. (objecting to a question about planned increases to the rate base); 1:29:15 to 1:30:00 p.m. (objecting to a question about data center contracts, stating "our interest, your honor, is is keeping the scope of this hearing narrowly tailored to the company's development of the IRP); May 14 HVT at 3:08:45 to 3:12:15 p.m.

[88] JI Ex. 1 at 7; May 13 HVT at 11:13:00 to 11:14:00 a.m.

[89] May 14 HVT at 3:08:45 to 3:12:15 p.m.

ever. Should one of those customers default, it would certainly be impactful for the Companies' financials, and the remainder of the Companies' ratepayers.

However, that should not be the only reason for taking a more nuanced look at the Companies' financials and ratepayer impacts. If ratepayer affordability is a concern of the Commission (and the Joint Intervenors firmly believe not only that it should be, but that it *is*), then the IRP process, and specifically the requirement for analysis of the Companies' financial information, is perhaps the best place to require the *integrated planning* by utilities that may lead to greater affordability. The IRP regulation requires the most comprehensive look the public and the Commission has at the "historical and projected demand, resource, and financial data, and other operating performance and system information, and … discuss[ion of] the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes."[90] With an eye towards "adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas," integrated planning, done right, can lead to greater affordability.

CONCLUSION

Joint Intervenors continue to recommend that future IRPs incorporate the recommendations offered in the AEC Report and Joint Intervenors' Initial Comment, and elaborated on in these post-hearing comments.

[Signature on next page]

[90] 807 KAR 5:058 Section 1(2).

Respectfully Submitted,

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CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, this is to certify that the electronic filing was submitted to the Commission on June 16, 2025; that the documents in this electronic filing are a true representation of the materials prepared for the filing; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

____
Byron L. Gary

Responses to Companies' Appendix

1. Page 28: "Instead, the Companies['] modeling assumes the end of essentially all demand side management offerings in 2030, just as load is nearing its projected peak."
    a. This statement is incorrect. The Companies modeled DSM programs throughout the analysis period.

Joint Intervenors Response:

The Companies included three distinct levels of energy savings from a combination of sources as a decrement to the IRP load forecasts. There was no modeling attempting to optimize DSM plan energy savings before or after 2030. The Companies included only demand response program savings in the IRP modeling.

The energy savings assumed in each load forecast decline as share of sales beginning in 2030. This is discussed in greater detail above at Section 1.a.

2. Page 34: "The 2024 IRP notes the Company has begun to assess offering a BYOB (Bring Your Own Battery) demand response program, but its deployment targets are exceedingly modest. The IRP projects peak demand savings from battery storage of 0.97 MW by 2030 and 1.77 MW by 2035. Contrast this with Massachusetts, which as of 2020 had installed 286 MW of customer-sited batteries within 2 years of program implementation or Green Mountain Power in Vermont, which had 2,500 customers participating in its BYOB program as of 2023."
    a. The Joint Intervenors do not provide any citations for their claims about Massachusetts or Green Mountain Power in Vermont, so it is unclear where the Joint Intervenors are getting their information.
    b. Regardless, as the Companies noted in their IRP, as of the end of 2023 the Companies' net metering customers had a total of 286 battery installations with a total battery storage capacity of 1.85 MW. These numbers are unsurprising because Kentucky has much lower electric rates than Massachusetts and Vermont, reducing price arbitrage opportunities across time-varying rates and for pairing with distributed generation. Rather than compare to utilities and states with vastly different rates and incentive structures, the Companies based their projections on peer utilities.

Joint Intervenors' Response:

a. With reasonable diligence, public information concerning distributed energy procurement programs in Massachusetts and Vermont is readily available through state agencies and utilities. Had Joint Intervenors known that the Companies were unfamiliar with how to obtain such public information, Joint Intervenors would have happily helped the Companies to understand how to investigate the practices and programs of industry leading utilities. In the future, particularly in non-adversarial, collaborative, and informal IRP proceedings, the Companies might reach out to their stakeholders for the help as needed.

b. Respectfully, it is a problem that the Companies, with minimum diligence, conclude they cannot do more to proactively support distributed energy resources. There can be differences between localities and also potential for substantial and cost-effective expansion of demand-side resources, where there is a willing utility. Joint Intervenors continue to encourage the Companies to consider more proactive support for distributed energy resources, as urged in Initial Comments.

3. Page 35: "Evaluate the use of rebates or other incentives to promote distributed energy resources, including demand response. … [Evaluate] reopening or creation of new curtailable service rider, large-load demand response, and[/]or direct load control programs[.]"
    a. Most of the expansion in the Companies' 2024-2030 DSM-EE Program Plan includes demand response expansion (Connected Solutions for residential customers and Business Demand Response for larger customers).
    b. The Companies continue to offer their nonresidential demand response program and enhanced it in the 2024-2030 DSM-EE Program Plan.
    c. The Companies' IRP did analyze expanding their existing Curtailable Service Rider, which proved to be uneconomical in all scenarios.
    d. The Companies' IRP did analyze certain DR program measures, which are included in the IRP Recommended Resource Plan.

Joint Intervenors' Response:

The referenced text is part of a bulleted list of recommendations at pages 34-35, and Joint Intervenors continue to urge credible evaluation of demand response programs. There is no disagreement here, and Joint Intervenors note that the Companies offer no further comments on the recommendations at pages 34-35.

4. Pages 36-37: "The Companies identify three factors that may inspire a DSM-EE Plan update, but none include cost-effectiveness of demand-side resources to mitigate higher costs of supply-side additions …. Perhaps that was an oversight, and the Companies would agree that … [their] guidestar remains provision of service through least-risk, least-cost portfolios."
    a. It was not an oversight; rather, because cost-benefit analyses are always part of DSM-EE planning, it seemed unnecessary to say. Moreover, the Companies have consistently and repeatedly said their goal is the provision of safe and reliable service at the lowest reasonable cost. Nothing about that has changed.

Joint Intervenors' Response:

The Companies' actions speak more loudly than their words, beginning with not having a credible evaluation of demand-side management savings potential, as discussed above in Section II.A. DSM-EE programs are least-cost resource alternatives, with cost-effectiveness signaling that those energy savings are lower cost than supply-side resource alternatives. That is presumably why, after the 2021 IRP did not evaluate continuing DSM/EE programs beyond the then-approved program term, the Companies' post-hearing data responses affirmed a commitment, offered first at hearing in response to questions from the Commission, that any subsequent CPCN or PPA filing "would include a full analysis of cost-effective DSM-EE programs…"[91] That did happen in 2022, with a combined application for two new gas plants, a 2024-2030 DSM-EE Plan, and more.

Now, some years later, the 2024 IRP was performed without an updated demand-side potential study and without separate efforts to evaluate

[91] Case No. 2021-00393, Companies' Resp. to JI PH Q 1.b ("[I]f the Companies file an application for a CPCN or PPA (or some combination of the two) based on the results of the current RFP, they anticipate doing so toward the end of this year or early next year. As the Companies further stated during the hearing in this proceeding, any such application would include a full analysis of cost-effective DSM-EE programs . . . .")

optimal demand-side resource potential relative to changing system needs and supply-side costs and limitations. Although the Companies have since filed a new CPCN request, there does not appear to have been an adequately updated analysis of cost-effective DSM-EE programs. It appears that reanalysis was not even done as part of post-filing modeling evaluating whether to retain a retiring coal unit. If least-cost planning is the goal, the Companies cannot continue reflexively discounting the importance of updating demand-side analyses before sinking customer dollars on relatively expansive supply-side projects.

5. Page 37 (footnotes omitted): "Based on data responses, in 2024, the Companies sought a DSM-EE potential study addressing Residential, Commercial, and Industrial sectors. Presumably, such a potential study would recalculate avoided cost values used for cost-effectiveness screening and testing. But it is unclear whether or when that updated picture of cost-effective potential would be put to use through expanded and modified programs. Again, DSM-EE potential appears to be an afterthought, pursued after committing customers to billions of dollars in capital projects, if at all."
    a. DSM-EE was not an afterthought. As noted, the Companies are currently conducting a DSM-EE potential study and anticipate it will be final mid-year. But when the Companies were conducting their IRP analysis, they had just begun implementing their 2024-2030 DSM-EE Program Plan, which the Commission approved in November 2023. The likelihood that a great trove of achievable DSM-EE potential had appeared in less than a year is low at best.
    b. Moreover, the load additions the Companies anticipate in this IRP are extremely high load factor, making them unlikely candidates for cost-effective DSM-EE programming.
    c. As the Companies have repeatedly noted throughout the IRP itself and this proceeding, their load forecast includes energy efficiency assumptions (and related demand reductions) well beyond those included in DSM-EE programs.
    d. It is unclear what the Joint Intervenors mean by asserting the Companies have "commit[ed] customers to billions of dollars in capital projects" before conducting a DSM-EE potential study, but it is not within the scope of this proceeding, and there is no sense in which the Companies have unreasonably or imprudently "commit[ed] customers to billions of dollars in capital projects."

Joint Intervenors' Response:

a. There is a significant likelihood that a reasonable evaluation of demand-side potential would identify "a great trove of achievable DSMEE potential" because the Companies' existing potential studies are nearly ten years old and used inputs that were absurd at the time and are entirely indefensible now. This was explained in Case No. 2022-00402, and the Companies have yet to provide a corrected or updated potential study in the intervening years.

b. The load factor of new customers does not itself mean that cost-effective savings potential is not available in the Companies' service territories. There are existing customers wasting energy every minute of every day, and paying the Companies for every bit of that waste. The cost-effectiveness of a utility-funded DSM-EE program helping to eliminate such energy waste is affected by the significant increases in supply-side generation costs and capacity value.

c. There is no dispute that the load forecast included assumed energy savings of three different amounts, each bundling DSM/EE program savings with a variety of non-program savings. Joint Intervenors maintain that is not a reasonable or adequate approach to evaluating or documenting DSM-EE program potential in an IRP. The IRP could be improved by making explicit the annual program budget and savings assumptions, and providing access to the data supporting those forecasted budget and savings values. Program-related savings assumptions should be disaggregated from customer-initiated energy savings, CVR, and other non-program drivers of energy savings. In resource expansion modeling, demand-side resource alternatives should be evaluated on equal footing with supply-side resources, including energy efficiency program savings potential.

d. The Companies may be technically correct that they have not committed ratepayers to their proposed capital investments. As a practical matter, however, PPL certainly has been suggesting to shareholders that they can expect Kentucky electric customers to pay a return on and of investment for new capital investments in the first three years of this IRP totaling billions of dollars.

Finally, Joint Intervenors assume that the Companies agree that a reasonable and prudent utility does not make capital investments in new generation without first maximizing cost-effective demand-side resource potential.

6. Page 51: "[T]he Companies have made important improvements in this IRP yet still do not adequately evaluate all potentially cost-effective resource options and fail to do not [sic] provide the level of comprehensive analysis needed to support an actionable plan for the next 15 years."
    a. There is no support for the Joint Intervenors' assertion. They have conducted no modeling or cost-benefit analysis, which would be the minimum requirement for credibly asserting that the Companies have "not adequately evaluate[d] all potentially cost-effective resource options."
    b. The Joint Intervenors fail to understand the purpose of an IRP in Kentucky. It is not and never has been to provide "an actionable plan for the next 15 years." If that were its purpose, it would be unnecessary to file a new IRP every three years.

Joint Intervenors' Response:

a. Joint Intervenors maintain that their Initial Comment and AEC Report detail the support for the referenced assertion. Beyond that, the Companies may recall that this is a non-adversarial, collaborative, and informal proceeding, and no intervenor has an obligation to perform the sort of modeling that a reasonably prudent and diligent utility must do as part of integrated resource planning. Indeed, even if this were a formal, litigated proceeding with something like a burden of proof, that burden of proof would rest with the Companies, as it always does before the Commission.

b. Respectfully, the IRP regulation speaks for itself when it calls for utilities to report a 15-year plan, identify steps to be taken in the next three years to implement the plan, and identify possible barriers to successful implementation of the plan. Indeed, circumstances will change over time and no one suggests that the Companies should make capital investment on the basis of analyses that are two or three years old. IRPs are required every three years to ensure that sort of refresh is happening. At the same time, the Companies are making decisions today that will have implications over more than their 15-year IRP period; they're making decisions today to spend on new infrastructure with 40+ expected useful lives. If the Companies are unable to conduct 15-year planning with a degree of rigor capable of supporting investments even within that timeframe, that is a real problem.

7. Attachment JI-1 at 7 – 12 (9 – 14 of 58): "Best Practice A.1. Load Forecasting"
    a. The Joint Intervenors' consultant, Applied Economics Clinic ("AEC"), claims the Companies provided inadequate support for their residential customer forecast and data center forecast, but both forecasts are well-documented in the IRP and reasonable. In addition, all workpapers were provided when the IRP was filed. As discussed in IRP Volume II, the Companies' residential customer forecasts are specified econometrically as a function of population according to a reputable data source (S&P Global). The forecasts consider regional trends and account, for example, for the fact that customer growth differs in urban and rural areas. Unsurprisingly, forecasted customer growth is consistent with history in the nearterm and slows in the latter part of the planning period as the forecast of population slows.

Joint Intervenors' Response:

The AEC Report offers valid and well supported critiques of the Companies' load forecasts in this IRP proceeding and in the Companies' pending CPCN case. Also note that, but for out-of-model adjustments to add in new large load customer growth, the Companies' load forecast would reflect negative growth.

8. Attachment JI-1 at 12 – 15 (14 – 17 of 58): "Best Practice A.2. Demand Side Resources"
    a. Contrary to AEC's assertions, energy efficiency-related energy savings do not "drop rapidly after 2030" (page 17 of 28). Instead, as seen in Figure 7-2 of 2024 IRP Volume I, the combined impact of LG&E-KU-sponsored and customer-initiated energy efficiency improvements are assumed to increase throughout the IRP planning period.

b. AEC asserts that the Companies did not evaluate as part of the 2024 IRP "more aggressive options to increase use of the curtailable service rider and demand conservation program" despite the 2021 IRP Staff Report recommendation along those lines. This assertion is incorrect. The Companies' analysis of new dispatchable DSM programs and extended CSR program is well documented in the 2024 IRP Resource Assessment.

Joint Intervenors' Response:

a. The cumulative savings from LG&E-KU-sponsored and customer-initiated energy efficiency improvements do increase throughout the IRP planning period, as reflected in Figure 5 of AEC's Report. At Figure 6, the AEC Report further correctly documents that the annual incremental savings as a share of customer demand declines over the planning period. Both things are true.

b. The Companies' conclusory assertion to the contrary notwithstanding, more robust efforts to develop and explore demand conservation opportunities would materially improve future IRPs. Particularly at a time when the Companies are speculating about near-term high-factor load growth potential, it makes sense to be aggressive about finding headroom relative to peaks through demand conservation.

9. Attachment JI-1 at 15 – 17 (17 – 19 of 58): "Best Practice A.3. Behind-the-meter resources"

a. Contrary to AEC's assertions, the Companies' distributed solar forecasts are well documented and reasonable.
b. Furthermore, the Companies' forecast does not "omit" behind-the-meter batteries (page 19 of 28). As explained by the Companies, distributed battery storage installations are implicitly assumed to grow as customers grow. Given current penetration levels, this approach is reasonable and in no way diminishes the quality of the Companies' resource planning decisions.

Joint Intervenors' Response:

a. The Companies' conclusory assertion to the contrary notwithstanding, Joint Intervenors continue to urge that the Companies improve their evaluation of behind-the-meter resource potential in future IRPs.

b. "However, this growth rate assumes that above the 1 percent of peak threshold customers will be less likely to adopt behind-the-meter solar and ignores the potential for increased adoption rates if higher compensation levels were offered. The Companies' also provide little justification for their assumed growth rates in any scenario, which do not seem to be in line with previous growth on the Companies' systems and fails to address how Companies' decision-making can influence the rate of adoption or the cost-effectiveness of decisions such as imposing a cap on new net metering after 1 percent of peak load. With investment in behind-the-meter battery storage growing every year, the Companies' use of past adoption rates and excuses regarding limitations in past data collection are not adequate rationales for a continued practice of omitting behind-the-meter batteries from load forecasting."

10. Attachment JI-1 at 18 – 19 (20 – 21 of 58): "Best Practice A.4. Electrification loads"
    a. Contrary to AEC's assertions, the Companies' electric vehicle and electrification assumptions are well documented and reasonable.
    b. In addition, the Companies documented the ways their planning process appropriately accounts for climate change in their response to JI 1-53.

Joint Intervenors' Response:

The Companies' conclusory disagreement notwithstanding, the AEC Report accurately discusses best practices for addressing electrification loads in long-range resource planning and for more fully accounting for climate risks.

11. Attachment JI-1 at 19 – 22 (21 – 23 of 58): "Best Practice A.5. Large load customers"

a. The Companies' approach to forecasting large loads was reasonable. To the extent AEC is arguing the Companies should include in their load forecasts only announced economic development projects or those under contract, only the Companies' Low IRP load forecast (zero economic development load) would have been reasonable because, for example, the Camp Ground Road data center project was not announced when the IRP was filed. But an IRP load forecast with zero economic development load would clearly have been too low.
b. On the other hand, planning for all possible data center projects in the economic development queue (more than 6,000 MW) would almost certainly result in overbuilding generation.
c. The level of economic development load in the Companies' Mid and High load forecasts was reasonable when the Companies developed the IRP and appropriately reflected information available at the time.

Joint Intervenors' response:

a. The Companies present a straw man, not present anywhere in Joint Intervenors' comments or attachments. AEC only states that LG&E-KU has not adequately supported its forecast. As recommended in the AEC White Paper: "LG&E-KU should provide documentation and a clear rationale supporting its high expectations for data centers locating in the territory over the next five years. The Companies use of a 4 to 9 percent of total U.S. data center load is not consistent with the context given in reports to which they attribute those values: Those studies instead suggest much lower data center growth for Kentucky."[92]

b. The Joint Intervenors agree.

c. Companies' response in 11.c. is simply an assertion without support. Rather than grappling with the critique of this key part of their IRP, or pointing to specific justification already presented, Companies simply assert their own reasonableness. Extraordinary claims require extraordinary evidence, and the Companies have simply not presented such evidence, as discussed above in Section II.C.

[92] Initial Comments of Joint Intervenors, Att. 1 at 21-22.

12. Attachment JI-1 at 22 – 23 (23 – 24 of 58): “Best Practice B.1. All-resource RFP”

    a. As stated in the Companies’ Responsive Comments, it is unreasonable to expect that issuing RFPs for an IRP analysis will result in any useful data due to bidders’ anticipation that such an RFP is not for any actual need and due to the IRP’s 15- year planning horizon. It is therefore reasonable to use commercial information in the Companies’ possession and data from the U.S. Department of Energy’s National Renewable Energy Laboratory in modeling resources to obtain directional insight from the IRP.

    Joint Intervenors’ Response:

    Again, as in response to #6 above, the law requires the Companies to develop a 15-year plan, including identification of steps to be taken in the first three years of that plan. The IRP is real-world planning that is intended to have a direct relationship to real world action.

    The view that an RFP would categorically be out of place in an IRP process is unsurprising from the Companies; the Companies will go so far as to seek a CPCN without the benefit of a recent competitive bidding process. As a practical fact, the quality of both the IRP and CPCN suffer from the absence of information from market participants. To the extent that regulatory oversight is intended to operate as a substitute for market competition, Joint Intervenors urge regulatory skepticism whenever an investor-owned utility discourages information from or collaboration with market participants, particularly so with respect to large capital projects.

13. Attachment JI-1 at 23 – 25 (25 – 27 of 58): “Best Practice B.2. Modeled resources”
    a. AEC criticizes the Companies for not modeling a utility-scale solar-plus-storage resource. But as explained in the Companies’ response to SREA 1-1, pairing renewables with battery storage, and requiring battery storage to be charged only by the renewables, reduces the likelihood that the battery will be charged when needed and therefore reduces the value of the battery.
    b. AEC criticizes the Companies for “imposing artificial limits on renewable energy resources.” Given the incremental nature of portfolio changes in most scenarios, the Companies’ renewable energy limits are reasonable.

Joint Intervenors' Response:

a. A single factor assessment of the value of a battery resource—or any resource for that matter—is simply unserious. The unseriousness of the Companies' response is demonstrated by the broadly accepted practice of modeling and developing solar-plus-storage resources and the absence of any factual support.

b. Joint Intervenors continue to disagree. To remind the Companies of questions from the Commission in the 2021 IRP review proceeding: "If you know the model can make the appropriate economic choice, qualitative decisions aside, . . .why not just see what the analysis puts out." Case No. 2021-00393, July 12, 2022 Hearing ca. 8:23:40 (then-Commission Chair Chandler). The Companies have not raised any practical reason that less restrictive limits on renewable energy options in the modeling are possible; and the Companies should relax their restrictions and see what results.

14. Attachment JI-1 at 25 – 28 (27 – 30 of 58): "Best Practice B.3. Regulatory costs"
    a. AEC claims the Companies failed to fully evaluate carbon risk by not evaluating scenarios with a cost for carbon emissions. But the Companies appropriately evaluated carbon risk by modeling the regulation the EPA proposed to limit carbon emissions (i.e., the GHG Rule). The GHG Rule imposes significant costs on carbon emissions, albeit not through a carbon tax. A carbon tax or CO2 price may be an appropriate consideration in a future IRP if the GHG Rule is repealed.
    b. Additional responses to points AEC made in this section are below.

Joint Intervenors' Response:

First, there does appear to be agreement that it is important for a utility to attempt to evaluate carbon risk in integrated resource planning. Disagreement begins at the much more nuanced level of how to go about representing future uncertainty in modeling and planning.

Second, there never has been disagreement that the Companies' reasonably attempted to model the portfolio implications of the GHG Rule. Rather, the point here is that those modeling runs (the PVRR results of which are not shared in the 2024 IRP) did not fully evaluate carbon risk. Carbon risk could have been more fully evaluated as recommended by the AEC Report. Joint Intervenors continue to emphasize the importance of accurately evaluating, disclosing, and mitigating carbon emission risks of the Companies' generation portfolio.

15. Attachment JI-1 at 26 (28 of 58): The Companies' treatment of the GHG Rule as 'low likelihood' eliminates it from full consideration in identifying a least-cost plan …."
    a. The Companies also treated the "No New Regulations" scenario as low likelihood. It would be unreasonable to treat all possible future scenarios as equally likely when there are reasons to assign them different likelihoods.
    b. Moreover, as the Companies' GHG Rule modeling shows, the IRP Recommended Resource Plan includes resources that would be needed in the GHG Rule scenarios, particularly in the near term.

Joint Intervenors' Response:

a. No one suggested otherwise. The fact stands that the modeled outputs from the GHG Rule scenarios were cut from the process early and did not directly inform selection of the Companies' recommended plan.

b. Similarities in resource portfolios across modeling runs are interesting, but they do not displace the methodological critique being offered by the referenced portion of the AEC Report.

16. Attachment JI-1 page 26 (28 of 58): "Although the Companies' Recommended Resource Plan takes a 'no regrets' approach supports the elimination from consideration of potential CO2 regulation (as well as high economic development load growth), their modeling of the Recommended Resource Plan does not transparently demonstrate how the risk of future climate regulation was addressed."
    a. The Companies disagree. They were very clear about how they addressed future climate and other environmental regulation, and they were clear about how they selected the resources in the IRP Recommended Resource Plan. Whether the Joint Intervenors'

consultant would have chosen a different plan is another matter; simply having a difference of opinion does not make the Companies' approach unreasonable.

Joint Intervenors' Response:

The 2024 IRP does state the Companies' high level views on future regulation, but Joint Intervenors are unaware of anything in the 2024 IRP that considers or reports on how future climate regulation might impact the Recommended Resource Plan. This could have been accomplished by, for example, assigning a cost per ton for certain emissions, estimating possible carbon control costs (or replacement costs if carbon controls already known to be unfeasible), or quantifying the stranded asset risk exposure related to generation assets with significant pollution effects.

17. Attachment JI-1 at 26-27 (28 to 29 of 58): AEC criticizes the Companies for not modeling carbon pricing instead of or in addition to the final Greenhouse Gas Rules under Clean Air Act 111(b) and (d), suggesting the Companies' approach is somehow contrary to the Commission Staff's 2021 IRP Report.
    a. Commission Staff's 2021 IRP Report actually said this: Commission Staff also disagrees, in part, with statements in LG&E/KU's post-hearing comments indicating that recent developments support its assumption that carbon regulation is likely to be achieved through application of the NSPS alone. Commission Staff agrees that limitations imposed on the EPA in West Virginia v. EPA make it more likely that it would attempt to regulate carbon emissions through the direct regulation of generating facilities and statements from the current administration and incentives in the Inflation Reduction Act support that prospect. However, given questions about the feasibility of CCS, it is unclear whether the EPA could regulate carbon through constraints on specific generating units and such regulation could be held up for some time in litigation even if they did. Given the urgency with which many view the need to address carbon emissions, Commission Staff believes such issues and potential delays in other forms of regulation raise the prospect, particularly over a timeline of 15 years or more, that a federal price or tax on CO2 emissions could be implemented through the reconciliation process in the same way the tax on

methane emissions was imposed in the Inflation Reduction Act. Thus, Commission Staff believes that the regulatory risk or prospect of a tax on CO2 emissions should be seriously considered and discussed in detail in LG&E/KU's next IRP and any assumption regarding a CO2 price or tax, including that a CO2 price is unlikely, should be fully supported such that the reasonableness of the assumption can be assessed.

b. After the Commission Staff wrote its 2021 IRP Report but before the Companies filed their 2024 IRP, the EPA issued and finalized its Greenhouse Gas Rules. At the time the Companies filed their IRP, though the rules were being challenged, there was no indication of any pursuit at the federal, state, or local level of any kind of carbon tax or pricing approach that would have affected the Companies. It was therefore appropriate for the Companies to conduct their Greenhouse Gas modeling as they did, i.e., by modeling the effects of the final Greenhouse Gas Rules, not a set of hypothetical carbon prices.

Joint Intervenors' Response:

As the Companies' oft repeat, the 2024 IRP is a snapshot in time, and regulatory environments can be fast-changing. When there is a concrete rule applicable to the Companies' operation, it is reasonable to model that rule's impact. The Companies have not been criticized for their attempt to model GHG Rule impacts. That attempt was necessary but not sufficient to fully assess the portfolio's future emission risk.

18. Attachment JI-1 page 27 (29 of 58): "Mercury Air Toxics Standard (MATS) update: Adopted in early 2024, the standard most importantly lowers the limit for particulate matter (PM, as a surrogate to be measured for heavy metals) from 0.030 to 0.010 pounds (lbs) per million British thermal units (MMBtu). The Companies say they are already monitoring compliance at all applicable units, but the rule will mean a tighter margin between emissions levels and the limit, meaning exceedances could happen more easily and there would be more difficulty with monitoring at such refined levels. Additional compliance measures such as control efficiency or monitoring upgrades were not modeled in any scenario."

    a. The Companies' monitoring systems already comply with the MATS rule; additional upgrades are not warranted in the modeling. Incremental operations and maintenance costs to address enhanced preventative maintenance to address a lower compliance margin is not a material cost in the modeling process.

Joint Intervenors' response:

Joint Intervenors do not dispute that LG&E-KU's monitoring systems already comply with the MATS rule (and do not in fact have sufficient information to either confirm or deny the assertion). The Companies themselves, however, state that although their "historical operating data depicts compliance with the lower PM emission limit; nonetheless, this reduction results in a significant reduction in compliance margin and a significant increase in compliance risk. … The Companies are assessing the use of non-mercury hazardous air pollution traps monitoring equipment that is unaffected by the PM test criteria to minimize compliance risk and enhance compliance margin." The Companies could, therefore, either increase the margin between emissions and the limit, or change the type of monitoring used. Neither option is further evaluated in the IRP, however, beyond the quoted statement.

19. Attachment JI-1 pages 27-28 (29-30 of 58): "Fine Particulate Matter (PM2.5) NAAQS: This standard was lowered from 12 to 9 micrograms per cubic meter (µg/m3) effective May 6, 2024. The most recent data show only one monitor in the Louisville area exceeding the new standard. However, because EPA designates entire "Air Pollution Control Regions" based on the worst performing, or "design value," monitor in the region, the entire Louisville area could face a nonattainment designation. The designations process is ongoing, but a nonattainment designation could potentially come in early 2026, with attainment plans due late 2027, and a deadline to attain the standard likely being 2032. Like the ozone standard discussed in Companies' IRP, this means the Commonwealth and Louisville Air Pollution Control District will be responsible for driving local reductions to achieve attainment, including requiring Reasonably Available Control Technologies and Reasonably Available Control Measures (RACT/RACM) no later than 2031. Again, Companies failed to take potential additional control measures into account and model for the possibility of additional control upgrades being required."
    a. This comment shows a lack of understanding of the Companies' generation fleet. All units in the fleet contemplated for operation beyond 2031 will have RACT/RACM. The only units without RACT/RACM in the fleet at the time of the IRP submittal were Mill Creek 1, Mill Creek 2, and Ghent 2. As contemplated in the IRP,

both Mill Creek 1 & 2 would be retired by 2031, and the Companies included a Ghent 2 SCR in the IRP Recommended Resource Plan, which would ensure Ghent 2 would also have RACT/RACM.

b. The Companies have implemented what is arguably Best or Maximum Achievable Control Technology for particulate matter, Pulse Jet Fabric Filters. The NAAQS process relies on Reasonably Achievable Control technology for existing units. Thus, additional control upgrade considerations are not warranted.

Joint Intervenor's Response:

a. It appears that the misunderstanding may be the Companies'. RACT is a source-specific and pollutant-specific determination. 40 CFR 51.100(o). SCR, or selective catalytic reduction (SCR) controls for NO_X, a precursor to ground-level ozone, or smog. SCR does not meaningfully control for particulate matter (PM) emissions.

b. RACM "is any technologically and economically feasible measure that can be implemented in whole or in part within 4 years after the effective date of designation of a $PM_{2.5}$ nonattainment area and that achieves permanent and enforceable reductions in direct $PM_{2.5}$ emissions and/or $PM_{2.5}$ plan precursor emissions from sources in the area. RACM includes reasonably available control technology (RACT)." 40 CFR 51.1000. Requirements for RACT/RACM can change over time as control technologies improve, and what has been considered to be RACT previously may no longer be the most reasonably available control technology in the future. The Companies do not meaningfully present an evaluation of current RACT for particulate matter in the IRP.

20. Attachment JI-1 page 28 (30 of 58): "To comply with Commission Staff's 2021 instructions, the Companies should fully evaluate carbon risk in their scenario modeling by assigning a cost to carbon emissions. This scenario analysis should be directly and transparently included in the selection of a Recommended Resource Plan. Even though the fate of the current GHG Rule is uncertain, Commission Staff have instructed the Companies to consider carbon prices and climate regulations."

    a. This comment misrepresents Commission Staff's recommendations (not "instructions") in the 2021 IRP Report, as well as the Companies' IRP. See responses 17a and b above.

Joint Intervenors' Response:

Commission Staff's recommendations speak for themselves. Beyond that, please see responses 14 to 17 above.

21. Attachment JI-1 page 28 (30 of 58): "A future without limits to greenhouse gas emissions is unlikely. By failing to take full consideration of expected regulatory and financial risk related to climate change, the Companies are exposing themselves to over-investment in new gas resources (including gas co-firing modifications) that may become stranded assets when environmental regulations are strengthened. Stranded assets are a serious financial risk to the Companies long-term viability and could result in increased customer rates to pay for unused infrastructure."
    a. The Companies fully modeled the effects of the final Greenhouse Gas Rules, and the IRP Recommended Resource Plan includes resources that would be needed in the GHG Rule scenarios, particularly in the near term. Thus, this "omission" does not exist, and the near-term resources in the IRP Recommended Resource Plan are robust across a broad range of environmental regulatory scenarios, including one that includes the Greenhouse Gas Rules.
    b. According to the U.S. Energy Information Administration, "Natural gas is the single-largest source of energy used to generate electricity in the United States, making up 43% of electricity generation in 2023." Electric utilities and others are currently adding large amounts of gas-fired capacity: "In 2023, operators added 9,274 megawatts (MW) of new natural gas turbine generating capacity to the power grid in the United States."
    c. According to the National Renewable Energy Laboratory's 2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook, "Natural gas capacity continues to expand. In the Mid-case with current policies, natural gas capacity increases by 200 GW through 2050, whereas it increases by 130 GW in the Midcase with 95% net decarbonization imposed."
    d. According to the U.S. National Power Demand Study performed by S&P Global Commodity Insights for the American Clean Power Association, "[N]atural gas fired capacity and other firm resources like batteries will be critical to provide capacity and balancing

support[.] … By 2040, the US will require net additions of between 60 and 100 GW of gas ….”

e. Federal Energy Regulatory Commission (“FERC”) Chairman Mark Christie stated earlier this month, “When you run a roll call, it doesn’t take long to get to combined cycle gas as a baseload generating resource of choice. … Saying that it takes seven years to build combined cycle natural gas is not an argument not to do it, we have to do it.”
f. None of this suggests a high stranded asset risk for investing in gas-fired generation.

Joint Intervenors’ Response:

There does not appear to be any dispute regarding the observation that stranded assets are a serious financial risk to the Companies’ long-term viability and could result in increased customer rates to pay for unused infrastructure. Instead, the Companies appear to be insisting that this should not be a concern based on industry trends and statements of political appointees projecting continued and expanded reliance on gas generation. Respectfully, that’s a foolhardy position.

The Companies’ existing portfolio is dominated by fossil generating resources with the most significant regulatory risk exposure. The Recommended Resource Plan continues heavy reliance on generating resources with the most significant future regulatory risk, while reducing near-term use of renewable generation. The Companies call this a “no regrets” approach, and insist on not quantifying financial exposure to a known unknown: potential that fossil assets may be stranded sometime over the course of their accounting book life.

22. Attachment JI-1 at 28 – 31 (30 – 33 of 58): “Best Practice B.4. Fuel prices”
    a. AEC criticizes the Companies’ coal price forecasts. AEC notes that the MGMR prices conform to the AEO but argues that all other coal price scenarios are either too high or too low, based on the AEO’s very narrow range of coal price forecasts. AEO’s fuel price suggests coal and gas prices are not related and, for example, coal prices would be unimpacted by a switch to sustained high gas prices. Suggesting that the Companies should only consider the EIA’s narrow coal price range is dubious. The Companies

intentionally consider a much wider range of coal prices to capture a reasonably broad range of uncertain futures.

Joint Intervenors' Response:

AEC criticizes the Companies' coal price forecasts as "unconventional and frankly erroneous," resulting in "nonsensical" coal price profiles. Attach. JI-1 at 30 of 56. The Companies' coal price forecast method was developed in-house for the purpose of supporting gas plant proposals, has not been peer-reviewed, and is used by no other utility or stakeholder in the energy industry. The Companies do not have to use the AEO forecasts developed by the United States Energy Information Administration; but should be relying on sources and methodologies that are generally accepted and commonly used in the industry.

Further, to the extent that the Companies recognize a need to consider a wide range of coal prices to capture a reasonably broad range of uncertain futures, inventing a bespoke commodity forecast method is not a reasonable approach. There are modeling approaches designed to test a broad range of uncertain futures without distorting price inputs, e.g., stochastic modeling (which the Companies did not perform as part of this IRP effort).

23. Attachment JI-1 at 31 – 34 (33 – 36 of 58): "Best Practice B.5. Technology costs"

a. AEC claims the Companies' method for converting NREL technology costs from real to nominal dollars is "erroneous." This claim is incorrect. The Companies' methodology is documented in the 2024 IRP Technology updated and aligns technology costs with recent market-based cost estimates wherever possible.

Joint Intervenors' Response:

The AEC Report speaks for itself.

24. Attachment JI-1 at 35 – 37 (37 – 39 of 58): "Best Practice C.1. Future scenarios"; also Attachment JI-1 at 37 – 38 (39 – 40 of 58): "Best Practice C.2. Scenario assumptions"

a. AEC criticizes the Companies for only considering a handful of scenarios in their selection of a Recommended Resource Plan, but this criticism reflects a misunderstanding of the purpose of the IRP. The IRP is not a commitment to action. Indeed, the IRP contemplates a number of resource decisions over a 15- year planning horizon that would be imprudent to make today. Therefore, the method used to develop a resource plan for reporting in Sections 8 and 9 of 2024 IRP Volume I is reasonable.

Joint Intervenors Response:

There is no misunderstanding on the part of AEC or Joint Intervenors and no disputed issue of fact here either: The Companies considered only a handful of scenarios in their selection of a Recommended Resource Plan, and that unfortunately means the bulk of the modeling results were largely cast aside. As a result, the Companies' did proliferate modeling outputs, but very few of those modeling outputs informed its selection of the Recommended Resource Plan. Analysis worth conducting as part of an IRP process is worth incorporating into decision-making.

Again, as in responses 6 and 12, an Integrated Resource Plan process is expected to result in an actual plan. The plain language of the law puts this beyond reasonable dispute when requiring the Companies to provide "a plan" that specifies "[s]teps to be taken during the next three (3) years to implement the plan" and "[d]iscussion of key issues or uncertainties that could affect successful implementation of the plan." 807 KAR 5:058, Section 5. Integrated Resource Planning is real world planning, with real world results.

25. Attachment JI-1 at 38 (40 of 58): "Best Practice C.3. Base case"
    a. AEC asserts the Companies should have re-evaluated the "base case" (i.e., Recommended Resource Plan) over all scenarios for better risk assessment. Because the IRP is not a commitment to action and many resource decisions in a 15-year resource plan do not require immediate attention, this analysis is unnecessary. Re-evaluating the fixed 15-year "base case" over all scenarios presumes that the Companies would not adjust their Recommended Resource Plan over time as new information regarding technology pricing, load, environmental regulations, or fuel prices becomes available. For example, if the recent spike in

solar costs proves transitory and solar prices decline in the future as NREL projects, the Companies will modify future resource plans to include additional solar generation if those resources are identified as least cost at that time.

Joint Intervenors Response:

The Companies misunderstand the referenced critique. There is obviously a practical need to update modeling as inputs change and to take action based on the best, most recent information. No one has suggested otherwise. At the same time, modeling methodologies should do something to attempt to assess risk exposure given future uncertainty.

Again, as in responses 6, 12, and 24, an IRP is intended to be a real world planning effort that results in a plan that the utility provisionally expects to implement.

26. Attachment JI-1 at 38 – 39 (40 – 41 of 58): “Best Practice C.4. Resource portfolios”

    a. In addition to their PLEXOS modeling, AEC criticized the Companies for not developing and evaluating portfolios to meet other objective functions. But the Companies submit that focusing on developing resource plans to reliably serve customers at the lowest reasonable cost is appropriate.

Joint Intervenors’ Response:

The Companies misunderstand. Of course it is appropriate to develop resource plans capable of reliably serving customers at the lowest reasonable cost. In order to develop resource plans capable of reliably serving customers at the lowest reasonable cost, modeling tools can be used to “illuminate questions of policy or address financial risks related to key uncertainties.” Attachment JI-1 at 38 (40 of 58). This is an important part of maintaining reliable, least-cost service, as it enables concrete communication with policymakers and regulators about the implications of different policy questions and financial commitments.

27. Attachment JI-1 at 39 – 40 (41 – 42 of 58): “Best Practice C.5. Retirement analysis”

a. The AEC reiterates concerns regarding carbon prices and renewable limits, which the Companies address above. See responses to items 14, 17, and 20 regarding carbon prices. See response to item 13 regarding renewable limits.

Joint Intervenors' Response:

The referenced observations and recommendations in the AEC Report are reasonable and well-supported.

28. Attachment JI-1 at 40 – 42 (42 – 44 of 58): "Best Practice C.6. Optimization modeling"; Attachment JI-1 at 53 – 55 (55 – 57 of 58): "Best Practice E.2. Transparency and accessibility"
    a. AEC criticizes the Companies for a perceived lack of transparency, saying modeling results were not presented in a way that was easy to understand for nontechnical experts, and saying "Direct IRP modeling experience and/or an advanced degree in economics should not be a limiting factor in stakeholders' ability to access and interpret basic IRP findings, including quantitative comparisons of key metrics across resource plans and scenarios." The Companies strive for transparency by thoroughly documenting their work product and making as much information publicly available as reasonably possible. But due to the necessarily complex nature of resource planning, a level of expertise will be required to digest some of the Companies' workpapers and understand whether rules and regulations from other jurisdictions are applicable to the Companies.
    b. See also the response provided in the Companies' Responsive Comments.

Joint Intervenors' Response:

Whether or not the 2024 IRP transparently reports "basic IRP findings, including quantitative comparisons of key metrics" can be determined regardless of expertise. For example, no matter your expertise, you will not find PVRR results from the tens of modeling runs the IRP talks about. The Companies' decision to bury portfolio PVRR results in workpapers is particularly curious in light of the Companies' apparent view that PVRR results are the sole financial metric relevant to its resource planning.

As the Companies continue to "strive for transparency," one useful strategy could be to credit the feedback of stakeholders when they highlight specific metrics that can be reported on the face of an IRP.

29. Attachment JI-1 at 42 – 44 (44 – 46 of 58): "Best Practice C.7. Uncertainty analysis"
    a. AEC criticizes the Companies for not performing stochastic modeling for risk analysis, but the Companies' scenario modeling is more than adequate for this purpose. Scenario analysis is a form of stochastic modeling.

Joint Intervenors' Response:

Stochastic models analyze possible outcomes by accounting for randomness in one or more viable over time. This is different from deterministic models, which use known inputs and fixed parameters to identify a single outcome. Scenario analysis is a form of deterministic modeling: the Companies defined all the inputs and parameters and the model solved across time for a single outcome.

30. Attachment JI-1 at 44 – 46 (46 – 48 of 58): "Best Practice D.1. NPV comparison"; Attachment JI-1 at 50 – 51 (52 – 53 of 58): "Best Practice D.4. Recommended plan"
    a. AEC claims the Companies failed to compare PVRR in their workpapers and across all scenarios. The Companies performed PVRR analysis within each load and environmental scenario to determine the optimal resource plans. AEC again misunderstands the purpose of the IRP, expecting a level of evaluation as though the Recommended Resource Plan were a firm commitment to action.

Joint Intervenors' Response:

Please see responses 6, 12, and 24.

31. Attachment JI-1 at 46 – 48 (48 – 50 of 58): “Best Practice D.2. Scorecard evaluation”; Attachment JI-1 at 49 (51 of 58): “Best Practice D.3. Quantitative assessment”
    a. AEC criticizes the Companies for not having a scorecard evaluation. The Companies objective is to provide reliable service at the lowest reasonable cost. Meeting this objective will properly account for all factors that impact utility revenue requirements.

Joint Intervenors’ Response:

It is unclear how the Companies’ circuitous response relates to AEC’s recommended scorecard evaluation approach.
With respect to the Companies’ stated objective, Joint Intervenors posit that a narrow focus on supply-side resource decisions excludes a great many factors that impact utility revenue requirements. The revenue requirement impacts of distribution and transmission planning are at least as significant and must be evaluated as part of integrated resource planning going forward.

32. Attachment JI-1 at 52 – 53 (54 – 55 of 58): “Best Practice E.1. Stakeholder process”
    a. AEC criticizes the asserted lack of a stakeholder process. As the Companies stated in response to JI 2-35: The Companies did not have a pre-filing IRP stakeholder engagement process and have not had such a process for any previous IRP. Unlike demand-side management plan filings for which there is a statutory requirement to consider the involvement of “customer representatives and the Office of the Attorney … in developing the plan,” the Commission’s IRP regulation neither requires nor contemplates a pre-filing stakeholder process. Rather, the IRP regulation provides a process by which the Commission Staff and intervenors may issue discovery requests and submit comments about an IRP after a utility files it. Likewise, the Commission may schedule conferences to discuss an IRP after a utility files it. But the regulation does not require or even suggest a pre-filing public or stakeholder process; rather, the post-filing IRP process prescribed by the Commission’s regulation is the stakeholder process. That notwithstanding, the Companies did engage with their DSM Advisory Group, including residential customer representatives, in two meetings prior to the

IRP filing (June 3 and July 16, 2024). The topic of the IRP arose in both meetings.

Joint Intervenors' Response:

Please see Section I above, discussing the Companies' efforts to minimize or even eliminate aspects of the IRP review process that the Companies insist "is the stakeholder process."