COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT REQUIREMENTS	**))))))))))**	**CASE No. 2022-00402**

INITIAL BRIEF OF JOINT INTERVENORS METROPOLITAN HOUSING COALITION, KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY, AND MOUNTAIN ASSOCIATION

Tom FitzGerald
Ashley Wilmes
Byron Gary
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602
(502) 551-3675
FitzKRC@aol.com
Ashley@kyrc.org
Byron@kyrc.org

Counsel for Joint Intervenors, Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association

Dated: September 22, 2023

CONTENTS

I. INTRODUCTION

Come the Joint Intervenors Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association ("Joint Intervenors"), and in accordance with the August 30, 2023 Order of the Kentucky Public Service Commission ("Commission") establishing an opportunity to file a post-hearing brief in support of their post-hearing positions on or before September 22, 2023, herewith file for the Commission's consideration, their joint position regarding the issues raised by the Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E-KU" or "the Companies") in their *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company For Certificates of Public Convenience And Necessity And Site Compatibility Certificates And Approval Of A Demand Side Management Plan And Approval Of Fossil Fuel-Fired Generating Unit Retirements* ("Joint Application").

For the reasons stated below, and on the basis of the record established in Case No. 2022-00402, including the expert testimony of Joint Intervenors' witnesses McDonald, Grevatt, and Sommer, Joint Intervenors recommend that the Commission:

1. Approve the proposed Demand Side Management and Energy Efficiency Plan (DSM/EE Plan), with modifications recommended by Witness Grevatt; direct the Companies to undertake reanalysis of energy savings potential in their service territories and a low-income market characterization study to enable data driven DSM/EE planning; and require the Companies to submit an updated DSM/EE plan proposal capable of achieving 1% annual savings as a percent of sales.

2. Approve the requested Certificates of Public Convenience and Necessity ("CPCN") and related site compatibility certificates for the Mercer County Solar Facility and the Marion County Solar Facility.

3. Approve the proposed fossil-fired unit retirements for Mill Creek Units 1 and 2, Haefling Units 1 and 2, and Paddy's Run 12, and conditionally approve the proposed retirement of Brown Unit 3 and Ghent Unit 2, with specific direction to the Companies on the reanalysis necessary in order to identify replacement resources able to satisfy the requirements of both KRS 278.264 and the standards for approval of a Certificate of Public Convenience and Necessity.

4. Deny without prejudice the requested Certificates For Public Convenience and Necessity for the proposed Mill Creek and Brown Natural Gas Combined Cycle Units ("NGCCs") and the Brown Battery Electric Storage System until such time as the Companies:

> a. Reevaluate, in light of more accurate costs of the replacement NGCCs, the cost-effectiveness of DSM and EE measures that could be implemented in order to reduce or manage demand and to reduce load, thus moderating and modulating the "need" for replacement generating units and assuring absence of wasteful duplication with demand-side measures that could be implemented at lower overall cost to ratepayers;
>
> b. Expand consideration of DSM and EE measures to include those recommended by Joint Intervenors' Witness Grevatt, and including a PAYS program;
>
> c. Evaluate the potential (1) for dispatchable customer-sited resources, (2) to increase the size or number of storage units, and (3) for hybrid solar and storage resources to cost-effectively meet system needs.

Lastly, Joint Intervenors express support for power-purchase agreements ("PPA") for the output of certain solar photovoltaic ("PV") facilities with a combined capacity of 637 MW; but disagree with the suggestion of establishing a separate PPA rider as opposed to alternatives, including cost recovery through base rates.[1]

This case presents what are, in essence, three distinct but, in this case, related categories of requests for consideration and approval by the Commission. In the following sections, Joint

[1] Due to limited time available, Joint Intervenors do not detail further their support for the proposed Mercer County Solar Facility, Marion County Solar Facility, and the proposed solar PPAs in the body of our brief, but reserve the right to respond to any arguments made on rebuttal.

Intervenors will address each of the Companies' proposed DSM/EE Plan, resource retirements, and new resource additions in turn.

II. 2024–2030 DSM/EE PLAN PROPOSAL

Joint Intervenors recommend approval of the Companies' proposed 2024–2030 Demand-Side Management and Energy Efficiency programs, with modifications as recommended in Mr. Grevatt's Direct Testimony. Joint Intervenors further recommend ongoing regulatory oversight, corrected potential studies and cost-effectiveness evaluations, and development of a low-income market characterization study.

A. Legal Standard

Review of LG&E/KU's proposed Demand-Side Management and Energy Efficiency Plan ("DSM/EE Plan") is governed by KRS 278.285. Principally, the Commission must determine the *reasonableness* of a proposed plan, informed by consideration of a non-exhaustive list of eight factors:

> (a) The specific changes in customers' consumption patterns which a utility is attempting to influence;
>
> (b) The cost and benefit analysis and other justification for specific demand-side management programs and measures included in a utility's proposed plan;
>
> (c) A utility's proposal to recover in rates the full costs of demand-side management programs, any net revenues lost due to reduced sales resulting from demand-side management programs, and incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs;
>
> (d) Whether a utility's proposed demand-side management programs are consistent with its most recent long-range integrated resource plan;
>
> (e) Whether the plan results in any unreasonable prejudice or disadvantage to any class of customers;
>
> (f) The extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the

amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan;

(g) The extent to which the plan provides programs which are available, affordable, and useful to all customers; and

(h) Next-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home.

If after consideration of these statutory factors, along with any other factors deemed informative by this Commission, it determines the plan to be reasonable, the plan should be approved. Apart from those factors, the demand-side management plan statute is not prescriptive with respect to timelines, savings targets, programs, or budget—so long as the plan is reasonable.

Reasonableness, of course, must be determined in light of the Commission's foundational obligations in respect to the regulation of monopoly utility companies.[2] These obligations include ensuring rates that are fair, just, and reasonable, and service that is adequate, efficient and reasonable.[3]

Where a proposed DSM/EE Plan is submitted for review in conjunction with a request for one or more CPCNs to construct new supply-side resources—rather than prior to such a request so that the programs could achieve all reasonable effects on demand and usage and possibly defer or delay the need for such supply side enhancements—there is an *additional* obligation imposed on the utility with respect to the sufficiency of a DSM/EE Plan. For as discussed in Section V, a significant aspect of the CPCN analysis of avoidance of wasteful duplication, as

---

[2] KRS 278.030(1); KRS 278.040; *see also* Case No. 2019-00277, *Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs*, Order at 11 (Ky. P.S.C. Apr. 27, 2020) (observing statutory obligation to ensure rates are fair, just, and reasonable at the outset of discussion of proposed DSM/EE plan).

[3] KRS 278.030(1); KRS 278.040; *see also* Case No. 2019-00277, *Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs*, Order at 11 (Ky. P.S.C. Apr. 27, 2020) (observing statutory obligation to ensure rates are fair, just, and reasonable at the outset of discussion of proposed DSM/EE plan).

well as the assessment of unmet "need," is consideration of all reasonable alternatives, including demand-side resources, mechanisms, and programs, that can moderate or reduce need at lower cost.

Commission Orders routinely encourage exploration of all cost-effective demand-side management programs. As noted in the Commission's February 17, 2011, Final Order in Case No. 2010-00222:

> The Commission believes that conservation, energy efficiency and DSM, generally, will become more important and cost-effective as there will likely be more constraints placed upon utilities whose main source of supply is coal-based generation. . . . [T]he Commission believes that it is appropriate to strongly encourage Meade, and all other electric energy providers, to make greater effort to offer cost-effective DSM and other energy efficiency programs.[4]

Like Meade County more than ten years ago, the Companies' main source of supply is still coal-based generation, and cost-effective DSM/EE programs remain important to delivering reasonable, adequate, and affordable service to customers.[5]

---

[4] Case No. 2010-00222, *In the Matter of Application of Meade County Rural Electric Cooperative Corporation to Adjust Electric Rates*, Order at 15–16 (Ky. P.S.C. Feb. 17, 2011) ("Meade County Rural Electric Coop. Order"); *see also* Case No. 2010-00204, *In the Matter of Joint Application of PPL Corporation. E.ON AG., E.ON US Investments Corp., E.ON U.S. LLC. Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities,* Order at 14 (Ky. P.S.C. Sept. 30, 2010) ("DSM, energy efficiency, and conservation are important now and will become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation.") (*see also* Meade County Rural Electric Coop. Order at 15; Case No. 2008-00408, *In the Matter of Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007*, Order at 22 (Ky. P.S.C. Oct. 6, 2011)).

[5] *See also* Case No. 2012-00221, *In the Matter of Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Order at 11 (Ky. P.S.C. Dec. 20, 2012): "with the potential for huge increases in the costs of generation and transmission as a result of aging infrastructure, low natural gas prices, and stricter environmental requirements, we will strive to avoid taking actions that might disincent energy efficiency."

B. The Proposed DSM/EE Plan should be approved, with modifications.

Joint Intervenors support approval of the Companies' proposed DSM/EE Plan, as enhanced and modified by the recommendations of Mr. Grevatt.[6] In the following subparts, Joint Intervenors: (a) summarize the Companies' proposal; (b) revisit the reasonableness of directing the Companies to develop a new plan targeting savings reflecting 1% of sales; (c) explain the indefensible character of the Companies' 2022 Cross Sector Potential Study Update and the need for a reassessment of savings potential; (d) discourage changes to income-eligibility thresholds for the Companies' sole program dedicated to households getting by with less than 200% FPL unless the Companies provide an empirical basis to show the reasonableness of a change in eligibility criteria and lack of adverse effect on those most in need. Joint Intervenors also address (e) survey shortcomings in the lackluster PAYS analysis, Ex. LI-3, and urge reassessment; (f) identify a mistaken point of law and urge the Commission to assert jurisdiction over DSM/EE Plans to the same extent that it may assert jurisdiction over supply-side resources, and (g) ask the Commission to protect customers by requiring the Companies to file a mid-plan update.

1. *The Companies' proposal*

The Companies have proposed a mid-plan adjustment to their 2019–2025 DSM/EE Plan to expand program budgets, make certain programmatic changes, and acquire certain equipment and analytical work products.[7] According to the Companies, the proposal will "make more

[6] Direct Testimony of Jim Grevatt at 5–8, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402 (July 14, 2023) ("Grevatt Direct").

[7] *E.g.*, Direct Testimony of John Bevington, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 17:10–16 (Dec. 15, 2022) ("Bevington Direct").

comprehensive energy efficiency and demand response opportunities available to a broader customer population."[8] The Companies' proposal would roughly triple the level of annual investment from $15 million to $45–$50 million, increase the 7-year cumulative MW energy efficiency savings by 2030 from 112 MW to 170 MW, and more than double the demand response savings available in 2030 from 86 MW to 207 MW.[9]

As the Companies' evidence shows, the proposed expansion of their DSM/EE Programs will be largely beneficial to all customers. These programs "contribute to a great customer experience and deliver high customer value"[10] by serving customers with energy *savings*. The Companies report their programs to be "highly successful," meeting or exceeding expectations across the board.[11] At scale, cost-effective energy efficiency provides "cost savings to customers in the long term by deferring or eliminating the need for more costly infrastructure investments."[12] Benefits extend beyond avoided energy, capacity, and wires costs to include improving bill affordability, reduced emissions and the attendant public health and economic gains, and safer, healthier, and more resilient homes.[13] These programs can and should be expanded to capture as much of the Companies' cost-effective potential savings as reasonably possible.

Joint Intervenors appreciate LG&E/KU's acknowledgement—and agree—that "DSM-EE is a vital part of the Companies' overall resource mix now and into the future . . . ."[14] Expansion of the Companies' existing DSM/EE Plan is reasonable, and overdue. The Companies should be

[8] Bevington Direct, Exhibit JB-1 at 2.
[9] Bevington Direct, Diagram at 3.
[10] Bevington Direct at 16:14–15.
[11] Bevington Direct at 4:7–10.
[12] Grevatt Direct at 10:8–11.
[13] *E.g.*, Grevatt Direct at 9:6–18; *id.* at 10:1–11:3.
[14] Bevington Direct at 6:21–22.

achieving more; and while Joint Intervenors support the expanded proposal (with a caveat regarding WeCare) there remain many measures that should be studied and adopted. A strong regulatory expectation by the Commission for even better performance by the Companies is needed.

2. *The Companies should revise their DSM-EE Plan with the objective of achieving efficiency savings equal to at least 1% of sales.*

The proposed DSM/EE Plan will "provide significant demand-side resources to help satisfy the Companies' projected load requirements,"[15] but it is still a drop in the bucket, frankly. The plan is too little, too late, to make any real difference in deferring, diminishing, or delaying a billion dollars of new gas generation, the Companies assert.[16] Setting aside that debate for the moment, there are good reasons to expect that the Companies could achieve much greater efficiency savings, as addressed by testimony from Jim Grevatt.

Mr. Grevatt, presently a Managing Consultant at Energy Futures Group, has worked in the energy efficiency industry since 1991.[17] He has served as the Director of Residential Energy Services at Efficiency Vermont and the District of Columbia Sustainable Energy Utility.[18] As the Manager of Energy Services at Vermont Gas Systems, Mr. Grevatt managed residential and commercial efficiency programs.[19] Earlier in his career, Mr. Grevatt gained extensive hands-on experience conducting hundreds of energy audits for Vermont's Low-Income Weatherization Assistance Program and Vermont Gas Systems' demand-side management programs.[20] Today,

[15] Bevington Direct at 18:11–14.
[16] Bevington Direct at 7:7–14. Joint Intervenors continue to dispute the Companies' assertion in this regard and will discuss below the effects of not modeling DSM/EE programs on equal footing with supply-side alternatives.
[17] Grevatt Direct at 1:3, 10; *see also* Grevatt Direct, Ex. JG-1 (Grevatt Résumé).
[18] Grevatt Direct at 2:11–12.
[19] Grevatt Direct at 2:12–14.
[20] Grevatt Direct at 2:14–17.

Mr. Grevatt advises regulators, utilities, program administrators, and a variety of advocacy groups, including environmental, low-income, and affordable housing advocates.[21] Here, Joint Intervenors sought Mr. Grevatt's opinion on the Companies' proposed DSM/EE Plan, supporting analyses, and planning process.[22]

Based on Mr. Grevatt's experience, he has concluded and advised that the Companies can and should be pursuing significantly more savings than they are aiming to with their proposed DSM/EE Plan. As a percent of their 2021 MWh sales, the Companies propose to achieve on average for 2024–2030, net savings of approximately 0.35%.[23] When scored alongside fifty-two large investor-owned utilities included in an analysis by the American Council for an Energy Efficient Economy ("ACEEE"), the Companies DSM/EE Plan would rank *below* forty peers.[24] On the basis of annual budget as a percentage of sales, the Companies' proposed DSM/EE Plan performs even more poorly, ranking below *forty-three* peers.[25] The unrebutted conclusion is that "the Companies are obtaining far, far less savings for their Kentucky customers than comparable utilities across the country,"[26] every single one of which has cost-effectiveness requirements similar to Kentucky.[27]

Mr. Grevatt recommends that the Commission require development of a new 2024–2030 DSM/EE Plan that ramps up to **achieve 1.0% gross energy efficiency savings as a percent of 2021 sales by 2027,** and maintains a similar level of efficiency savings through 2030, with an equitable balance between residential and non-residential savings.[28] As an illustration of how

[21] Grevatt Direct at 2:17–21.
[22] Grevatt Direct at 3:8–16; *id.* at 4:6–12.
[23] Grevatt Direct at 24:10–15.
[24] Grevatt Direct at 24:15–17.
[25] Grevatt Direct at 24:18–25:2.
[26] Grevatt Direct at 25:5–6.
[27] *See* Grevatt Direct at 47:4–5.
[28] Grevatt Direct at 7:1–8.

this could be done, Mr. Grevatt provides a portfolio of tried-and-true programs that could be deployed, and targets for additional savings from each.[29] To the extent that the Companies' goal here is truly to pursue "a robust and comprehensive suite of programs that will provide significant and necessary demand-side resources,"[30] they should be striving to attain *at least* the level of savings recommended by Mr. Grevatt.

Unfortunately, seemingly resigned to underperforming on all things demand-side related, the Companies use Ms. Isaacson's Rebuttal testimony to explain why cost-effectively achieving an average level of energy savings remains out of reach. That rebuttal has four prongs: (1) comparisons to utilities included in the Virginia Pathways Study are inappropriate for Kentucky utilities like LG&E and KU; (2) cost-effectiveness testing was not done on Mr. Grevatt's illustrative proposal; (3) confusion over whether savings were double-counted or programs rendered duplicative; and (4) the irrelevance of Ex. LI-1, the 2022 Cross-Sector Update in the Companies' program selection. These criticisms are misplaced.

3. *There is every reason to think that the Companies could be at least as capable as the leading electric utilities.*

First, in complaining about reference to the Virginia Pathways Study, the Companies missed the point. Comparisons to what similar utilities across the country have achieved in cost-effective demand-side management programs is a reasonable and appropriate practice. While countless variables can make utility programs more and less effective at capturing potential, empirical studies have shown that savings generally do not appear to vary significantly by

[29] *E.g.*, Grevatt Direct at Table 12.
[30] Rebuttal Testimony of Lana Isaacson, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 17:13–14 (Aug. 9, 2023) ("Isaacson Rebuttal").

geography.[31] State-by-state differences certainly exist, and can impact appropriate measures and program designs; and at the same time, there is nationwide availability of cost-effective savings potential.

The Companies know this, which is why their own planning process included *extensive* reliance on information, programs, and practices from other jurisdictions, including but not limited to:

1. Identifying potential energy efficiency and demand reduction programs, "Step 1" in the DSM/EE Planning process, "based on reviews of best practice programs, successful strategies offered by utilities in other jurisdictions . . .", *inter alia*.[32]
2. Relying on Cadmus' national experience and research focus to develop the list of 39 program options to be considered in late 2022.[33]
3. In program scoring by six individuals from Cadmus and Companies, including a factor weighing whether "the program [is] successful in any PPL territories,"

---

[31] *E.g.*, Grevatt at 29 ("An ACEEE analysis of forty-five potential studies found, by analyzing 'the relationship between savings and study time period, savings and census region (to assess possible geographical differences), savings and participation rates, and savings and avoided costs . . . [that] [i]t does not appear that savings vary by geography: there was equal representation across the country for a given level of savings.'").

[32] Bevington Direct, Ex. JB-1 at 10; *see also* Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Joint Intervenors' Initial Request for Information, Question 123(b) (Mar. 10, 2023) ("LGE & KU Response to JI Initial Q123(b)") ("The 'successful strategies offered by utilities in other jurisdictions' are included in the list of the 39 original programs considered and are part of the Companies' ongoing work, research, and collaboration including specific program and strategy requests from the DSM Advisory Group. The Companies did not categorize each program based on the source from which it was identified, nor did the Companies document the full description of the specific strategy for all the programs in other jurisdictions.").

[33] Bevington Direct, Ex. JB-1 at 10 (again in "Step 1", stating that "[t]hrough ongoing research and consultation with Cadmus, who advises utilities across the country on DSM/EE plans, the Companies created a comprehensive list of 39 potential programs . . .").

which would include Rhode Island, Pennsylvania, and Virginia.[34]

4. Once narrowed to 14 "selected" programs, "the Companies relied on . . . technical reference manuals from other jurisdictions" to compile a list of measures and practices.[35]
5. Cadmus's comparison of the LGE/KU potential study to "regional trends" was a comparison to neighboring Virginia, and a single data point: Dominion Energy's recent potential study.

Learning from what works in terms of program design and administration from other jurisdictions is eminently reasonable, and Joint Intervenors are encouraged that despite the criticism levelled at the Grevatt testimony in this regard, the Companies do in practice profess to look to other jurisdictions in their program planning process.[36]

It is unproductive, therefore, to summarily dismiss that Mr. Grevatt's references to the *Pathways for Energy Efficiency in Virginia* ("VA Pathways") report.[37] VA Pathways was not referenced to impose another state's standards on the Companies;[38] but to demonstrate what is possible and realistically achievable by the Companies.[39] The Companies have offered no evidence to explain why they are uniquely incapable of achieving greater efficiency savings – indeed, they have celebrated the successfulness of their existing programs. If the Companies

[34] Bevington Direct at 10; Aug. 28, 2023 HVT at 18:14:00–18:15:10 (confirming that Companies consulted its out-of-state utility affiliates on types of demand-side programs and how they work).
[35] Bevington Direct, Ex. JB-1 at 10.
[36] Here, Joint Intervenors would distinguish "program planning" and potential studies. In potential studies, focus on local, ground-up data is superior to cherry-picking out-of-state data. *Contra e.g.*, Isaacson Direct, Ex. LI-1 at 5 (saturation of LED lighting in 2016 and 2017 studies for LGE/KU was low, and in the potential study update, Cadmus "increased the overall saturation of LED linear lighting to align with site visit data collected in other jurisdictions . . ."); LGE/KU Resp. to JI 2.31(b) (Cadmus did not analyze jurisdictional differences before applying out-of-state site visit data on LED saturation to LGE/KU's 2022 Cross Sector Update).
[37] *Cf.* Isaacson Rebuttal at 1–4.
[38] Isaacson Rebuttal at 3:5–7.
[39] Grevatt Direct at 36–39.

could be at least as capable as the **twelve** investor-owned utilities benchmarked in VA Pathways, it is reasonable to expect cost-effective savings reflecting 1% of retail sales.

a. Robust analyses are needed for sound planning, and it is the <u>Companies'</u> responsibility to do credible work.

Mr. Grevatt's recommends that the Commission direct the Companies to reevaluate potential and territory-specific customer need, and to propose a revised DSM/EE Plan through 2030 that ramps up to achieving savings reflecting 1% of retail sales by 2027 and maintains those savings through 2030. Mr. Grevatt provides examples of the sort of analytical improvements that are both doable and needed—namely, reasonable assumed values for avoided capacity costs and all other components used in evaluating program cost-effectiveness; updated measure characterizations and territory-specific measure saturation data; and a low-income market characterization study capable of informing program design that is accessible and useful all residential customers. Mr. Grevatt offers an illustrative portfolio of programs, which based on his thirty years of experience, could be a plausible means of meeting 1% savings.[40] Mr. Grevatt did <u>not</u> recommend that particular portfolio be implemented, and did <u>not</u> claim to have done territory-specific cost-effectiveness testimony. In Mr. Grevatt's own words:

> My recommendation to the Commission is that it require the Companies to develop a revised 2024–2030 DSM-EE Plan that broadly reflects my recommended levels of savings and that the Companies iterate the program designs to identify cost effective approaches. In this process, it is critical that the Companies do not take the same shortcuts they took with the proposed 2024–2030 Plan: omitting consideration of programs that achieve high levels of savings for other utilities without assessing their cost-effectiveness at all, let alone with the $0 avoided capacity costs used in the potential study analysis. If the Companies do not find that these levels of savings are cost effective, the onus should be on them to transparently demonstrate that they have made every effort to identify program paths to achieve the targeted savings.[41]

[40] Grevatt Direct at 60–61; *see also* Aug. 29, 2023 HVT at 15:01:01.
[41] Grevatt Direct at 47:7–48:4.

At no time does Mr. Grevatt agree to assume the Companies' burden of providing adequate, reliable, and affordable service.[42] Nor has Mr. Grevatt assumed the Companies burden of adducing credible analyses in support of their filings.[43] It remains the Companies' obligation to seek to maximize cost-effective energy savings through effective, accessible programs.[44] By aiming for a reasonable level of savings achieved by average utility performers, the Companies can deliver system-wide and participant savings to customers.[45] The burden of demonstrating the reasonableness of the DSM/EE plan is assigned to the Companies by statute and cannot be delegated or shifted to commenters seeking to assist in developing the most robust program advancing the goals established by the statute.

b. Mr. Grevatt's illustrative portfolio neither double-counted savings nor unreasonably duplicated programs and measures.

Contrary to the Companies' claims on rebuttal, the illustrative portfolio offered by Mr. Grevatt does not double-count savings or unreasonably duplicate measures. Ms. Isaacson is simply mistaken with respect to how Mr. Grevatt accounted for HVAC savings in his program savings calculations.[46] As reflected in workpapers, the savings the Companies proposed for

[42] *See also*, Grevatt Direct at 51:12–16 ("the Commission should expect [the Companies] to thoughtfully consider alternative approaches that could lead to improved cost-effectiveness and increased savings. Fundamentally, it is consistent with the utilities' least-cost obligation to actively research, iterate, and propose cost-effective solutions to reduce energy waste through DSM-EE programs.").
[43] KRS 278.430.
[44] Aug. 29, 2023 HVT at 14:59:50–15:00:50 (addressing unfortunate lack of credible potential studies in record, utility obligation to pursue least-cost planning including pursuit of cost-effective savings potential, and the necessity and reasonableness of making comparisons to other utilities' performance).
[45] Rebuttal Testimony of Stuart A. Wilson, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 33–34 (Aug. 9, 2023) ("Wilson Rebuttal") (explaining that addition of Mr. Grevatt's recommended program costs and savings improved the PVRR for the Companies' preferred portfolio by $51 million).
[46] Isaacson Rebuttal at 4:1–5:3.

Residential HVAC rebates as part of the Online Audit program are ***subtracted*** in Mr. Grevatt's proposal *before* adding cost and savings potential through an additional program.

With regard Ms. Isaacson's concern that more specificity would be needed before pursuing additional savings via a residential behavior program,[47] she is not mistaken. But again, Mr. Grevatt is not foisting a turnkey, ready-for-implementation plan for LG&E/KU. That is the Companies' responsibility. While Joint Intervenors disagree with Ms. Isaacson's duplication concern, it is pointless to argue specifics of hypothetical program further, when the recommendation is that the Companies study and develop those details as they would for any plan.

c. The Companies did not evaluate DSM/EE program savings on equal footing, instead making planned savings and input to the supply-side modeling.

In her rebuttal testimony, Ms. Isaacson notes that "[t]he potential study . . . had no impact on the cost-effectiveness of the programs the Companies considered for inclusion in the DSM-EE Plan."[48] No one has suggested otherwise. But the problem underlying the Companies' proposal is that they rely on how well their proposed savings align with the results of the 2022 Potential Study, and claim that alignment shows their proposed program expansions will aim to achieve a reasonable portion of the identified potential. That is the entirety of the evidence used to show that the Companies "put together the most aggressive, responsive DSM program . . . to see if [the Companies] can avoid any of these costs" on the supply-side.[49] Preliminary program savings were provided to the load forecast group in October 2022; the load forecast became an

[47] *See* Isaacson Rebuttal at 4–5 (sharing unfamiliarity with residential behavioral programs and related program design considerations or potential).
[48] Isaacson Rebuttal at 14:12–14.
[49] Aug. 23, 2023 HVT at 09:31:00 to 09:33:00.

input to the supply-side modeling. The potential for greater levels of DSM/EE program savings was never evaluated as part of the 2022 Resource Assessment.

Although the Companies' witnesses claim that their DSM/EE Planning effort is serious, accelerated, ambitious, and always progressing, the Companies did not task Cadmus with updating the 2016 and 2017 potential studies until August 2022. That delayed request was in time to make Ex. LI-1 available to this record; but not in time to inform the Companies' late 2022 DSM/EE planning process.[50]

This is why it is necessary to start ramping up cost-effective programs immediately *and* go back to the starting gate to more thoroughly and reasonably assess energy savings potential. In order to identify achievable potential and effectively design programs that go after those savings and serve all customers, the Companies need to perform a radically improved potential study grounded in credible assumptions.

4. *The 2022 Potential Update is indefensible, and a credible re-analysis of achievable savings potential is needed.*

Reasonable minds should be able to agree: the Companies are capable of doing at least as well as their peers in terms of effective DSM/EE program design and implementation; and the 2022 Potential Update (Ex. LI-1) is not a credible or valid study of energy savings potential in the Companies' service territories. The Companies/Cadmus's nominal 2022 Potential Update neglected to update several key inputs, including measure characterizations, avoided capacity costs, and avoided fuel costs, and relied on arbitrary assumptions unsupported by data.[51] These inputs and assumptions are so material to the analysis that the decision to continue relying on

[50] LG&E-KU Resp. to Initial JI Q 146(c) (confirming that Cadmus conveyed the 2022 Potential Study to the Companies on November 30, 2022, after DSM/EE Plan proposal was already final). *Contra* Isaacson Rebuttal at 13 ("Yes, the Companies used the potential studies as a tool to inform the DSM-EE Plan.").
[51] Grevatt Direct at 26:7–29:4.

inputs and assumptions from 2016/17 vintage studies made the nominal 2022 Potential Update indefensible.[52]

With respect to measure characterizations, technologies have developed considerably since 2016, particularly in areas relevant to the Companies service territories, such as cold climate heat pumps that could deliver savings to customers still relying on electric resistance heating.[53] That entire category of potential, among others, was missed as a result of the decision to stick with the 2016/17 vintage measure characterizations.[54] It is unreasonable to evaluate savings potential on the basis of outdated measure characterizations.

The importance of updated avoided capacity cost assumptions should be equally obvious. Yet, inexplicably, the Companies/Cadmus also persisted in using $0.00 avoided capacity cost value for determining cost-effective savings potential in their potential studies, most concerning including Ex. LI-1. That decision was made despite the Companies being aware since at least October 2020 that a capacity need was likely by 2028 due to economic coal unit retirements;[55] despite having a draft analysis of how future avoided capacity cost values could be represented across multiple years;[56] and despite fundamental obligations to spend customer money prudently and make data-driven decisions about demand-side management's potential to cost-effectively contribute to meeting customer needs.

On behalf of the Companies, Ms. Isaacson's rebuttal does not attempt to directly rebut *any* of these fundamental flaws in the 2022 Potential Study observed by Mr. Grevatt.[57]

---

[52] *See generally* Grevatt Direct, Sec. IV at 25:14–35:8.
[53] Grevatt Direct at 30:1–3.
[54] Grevatt Direct at 29:14–30:4.
[55] LG&E/KU Resp. to Staff Post-Hearing Request Q-7.
[56] Joint Intervenors' Hearing Ex. 2, Case 2021-00393, *In the Matter of Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, LG&E/KU Resp. to JI Post-Hearing Request No. 13, with attachment (July 18, 2022) ("JI Hearing Ex. 2").
[57] Isaacson Rebuttal at 13:3 to 14:14.

Instead of attempting to rebut any of Mr. Grevatt's critiques about the 2022 Potential Study, the rebuttal misleadingly defends that Ex. LI-1 "had no impact on the cost-effectiveness of the programs the Companies considered for inclusion in the DSM-EE."[58] That is not surprising. The potential study could not possibly have contributed to program development and evaluation because: (1) it was not finished until *after* program cost-effectiveness testing was finished;[59] and (2) on its face, the potential study did nothing to evaluate programs or support program selection.[60] But the fact that the 2022 Cross-Sector Potential Study has nothing to do with the development of the proposed DSM/EE Plan does nothing to excuse it flaws. To the contrary, it makes the potential study update both indefensible *and* pointless.[61]

Apparently, the Companies did not recognize the serious flaws in Cadmus's studies. For one thing, no one knows the avoided cost values used in the potential studies simply by reading Ex. LI-1. If you want to know the inputs used, you have to ask—whether you are the Companies engaging with Cadmus; a state regulator tasked with overseeing monopoly utilities; a DSM/EE Advisory Group participant trying to collaborate in planning; or an intervening party represented by counsel and able avail yourself of formal discovery.

Whether knowingly or not, the Companies' testimony and evidence mistakenly emphasizes how the proposed DSM/EE plan's projected savings are "consistent with the

---

[58] *Id.* at 1:21–22.
[59] Isaacson Direct, Ex. LI-1 at 1 (dated Nov. 30, 2022); LG&E/KU Resp. to JI Initial Q1.146(c) (confirming that Companies received Ex. LI-1 from Cadmus on Nov. 30, 2022).
[60] Isaacson Direct, Ex. LI-1 at 2, n.3 ("This analysis does not consider Program potential because the Companies were not considering particular programs in this potential update.").
[61] *See e.g.*, Isaacson Direct, Ex. LI-1 at 5–6 (explaining that "[t]he 2043 values represent the adjusted market potential projection, whereas the 2035/2038 values represent[] the previous potential studies' results . . . . The achievable potential results represent the adjusted achievable scenario results as defined in the previous studies."). If the 2022 Cross-Sector Potential Study just presents results that represent 2016/2017 vintage studies using the same scenarios, it is hardly an "update" to the data and assumptions previously used and hardly makes an effort to account for changed circumstances.

numbers identified as achievable from the most recent potential studies and updates by Cadmus."[62] The Companies make repeated claims about reaching their savings potential to show the reasonableness of their DSM/EE Plan proposal.[63] Joint Intervenors believe these mistakes should be acknowledged and required to be corrected.[64]

Joint Intervenors encourage the Commission to send clear direction that reanalysis is needed, and the lack of credible data and transparent analysis here must not be repeated going forward. Every recent study the Companies have commissioned to determine economically achievable efficiency savings potential in their service territories uses an avoided capacity cost value of $0.00 when attempting to determine the difference between *technical* and *economically achievable* savings potential.[65] This means, as explained by Mr. Grevatt, comparisons to the 2022 Potential Study Update are meaningless, having nothing to do with the Companies actual avoided capacity cost value used elsewhere in the analysis:

---

[62] Bevington Direct at 12:21–23; *see also* LG&E/KU Resp. to JI Q-1.108(a).

[63] *E.g.*, Isaacson Direct at 5:17–18 ("DSM-EE Program Plan will allow the Companies to reach their program DSM-EE potential"); Direct Testimony of Tim A. Jones, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 20 (Dec. 15, 2022) ("Jones Direct") ("Notably, the Companies' forecasted energy savings resulting from energy efficiency compare favorably to the energy savings projected for achievable cumulative energy efficiency potential shown in Table 1 of the Cadmus 2022 Cross-Sector DSM Potential Study Projection (Exhibit LI-1 to the Direct Testimony of Lana Isaacson)."); Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Staff's Initial Request for Information, Question 33(a) (Mar. 10, 2023) ("LGE & KU Response to Staff Q33(a)") (asserting that "The Companies' assumed energy-efficiency savings are already near or at the upper bounds of reasonableness given existing technology and economics.").

[64] Joint Intervenors note, regrettably, that the Companies post-hearing data responses continue to rely on Ex. LI-1 as a benchmark for achievable potential in their territories. *E.g.*, Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Commission Staff's Post-Hearing Request for Information, Question 2 (Sept. 15, 2023) ("LGE & KU Response to Staff PH Q2") Q-2 (relying on Ex. LI-1 to estimate achievable potential in certain programs). Like the potential study itself, this continued reliance on an indefensible study is concerning, and suggests the Companies are unwilling to admit and correct past mistakes voluntarily.

[65] Grevatt Direct at 26.

> The most fundamental flaw is that the "analysis did not entail a measure or fuel cost update or cost-effectiveness model re-run." This is shocking, because the 2017 Study assessed cost-effectiveness using a $0.00 capacity avoided cost, whereas the Companies estimated avoided capacity cost in the instant case is $136.20. So, despite the Companies' statement that the "avoided cost of capacity has significantly increased since the Companies' most recent DSM-EE Program Plan filing [which] positively impacts the cost-effectiveness of certain DSM-EE programs," they did not reflect the current avoided capacity costs when determining economic or achievable potential in the 2022 update. Given this, the Companies' finding that the savings from the proposed 2024–2030 DSM-EE Program Plan "are consistent with the numbers identified as achievable from the most recent potential studies and updates by Cadmus" is a meaningless comparison.[66]

The Companies have not presented a sound empirical basis to doubt the magnitude of potential economically achievable savings still available to customers.

Experience tells us that there are likely considerably more economically achievable savings than claimed by the Companies' evidence in this case.[67] Contrary statements are unsupported and not credible.[68] There is no legitimate reason explaining why the Companies should be "obtaining far, far less savings for their Kentucky customers than comparable utilities across the country."[69]

Whatever level of savings the Companies are ordered to pursue at the conclusion of this proceeding, Joint Intervenors request the Commission to also require a credible potential study. To the extent that the Commission lacks confidence in the Companies' ability to work with credible consultants that can be relied upon to apply rigorous methods, credible data and assumptions, and transparent reporting of process, observations, and judgments, the Commission

---

[66] Grevatt Direct at 26–27.
[67] *See generally* Grevatt Direct.
[68] Consider, for example, the significant and admitted positive impact of updated avoided capacity costs (*e.g.*, Bevington Direct at 5:20–24 ("[T]he Companies' avoided cost of capacity has significantly increased since the Companies' most recent DSM-EE Program Plan filing. This avoided cost change positively impacts the cost-effectiveness . . ."); alongside (1) recognition of a probable 2028 capacity need, and (2) the decision against updating the $0.00 avoided capacity cost value at any time over the last (nearly) three years for any study of achievable cost-effective savings potential.
[69] Grevatt Direct at 25:5–6.

might consider close oversight or an investigative project launched by the Commission's technical staff. However accomplished, the Companies' reassessment of economic potential should be pursued immediately, be grounded in accurate data and reasonable assumptions, and reflect the rigor and transparency that Kentuckians deserve from regulated monopoly utilities.

And in the meantime, the Companies should immediately begin scaling programs to achieve savings reflecting 1% of annual sales by 2027 and maintain that level of savings through 2030. This is a significant increase above existing budgets and savings expectations, but that speaks more to past failures to propose and adopt more robustness measures. Even with the increases recommended by Joint Intervenors, the Companies plan would "remain[] well below the level of portfolio savings that has actually been achieved by the twelve leading utilities identified in the VA Pathways projects . . ."—a "significant and more compelling" benchmark for potential "than the flawed potential study prepared by Cadmus and adopted by the Companies." [70]

5. *The Commission should hesitate to modify eligibility criteria for income-qualified programs until the Companies develop empirical reasons supporting reasonableness of changes.*

Whatever level of savings the Companies pursue in their 2024–2030 DSM/EE plan, the Companies need to collect and consider data about the extent and character of energy savings needs, particularly for their most economically vulnerable customers. That need is made plain with the Companies' arbitrary proposal to change the income-qualification threshold for their low-income weatherization program to 300% FPL. With an empirical basis to make reasoned judgments, program design can be tailored to better serve customers. But without data, eligibility criteria changes to income-qualified programs are arbitrary, and may result in reduced

[70] Grevatt Direct at 42–43.

opportunities for customers below 200% FPL who already do not have many avenues to achieve savings or participate in DSM/EE programs.[71]

The Companies' proposal to increase WeCare program eligibility to 300% FPL[72] exemplifies the problem, as the Companies suggest this change without any supporting data whatsoever.[73] Because the Companies historically failed to track income data for customers or within their service territories—using public data or otherwise—the Companies have no data to appreciate how large the pool of potentially eligible customers is at any given income threshold.[74] The Companies do not know how many years it would take the WeCare program, at the proposed budget level, to serve the entire pool of customers eligible below 200% FPL—or at any other eligibility threshold.[75] Armed with no knowledge whatsoever about the scope of the need in their service territories at the existing eligibility threshold, the Companies have proposed a significant increase in the threshold, which may adversely affect those most in need by diluting available resources.

Attempting to illustrate the potential magnitude of this unknown, but knowable, information, Mr. Grevatt offered a "crude estimate" that the Companies could have a pool of customers below 200% FPL in the ballpark of 240,000, with perhaps something like 32,000 households between 200 and 300% FPL.[76] At that level, serving a rate of 5,400 households per

---

[71] Aug. 28, 2023 HVT at 18:29:24 (Mr. Bevington observes that there are "not a lot of options" for low-income customers to participate in DSM/EE programs).
[72] Isaacson Direct at 6:7–8.
[73] Grevatt Testimony at 14–15 (citing Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Joint Intervenors' First Supplemental Discovery Requests, Questions 11(a) and 11(b) (May 4, 2023) ("LGE & KU Response to JI First Supplemental Q"); *see also* LG&E/KU Resp. to JI Initial Q109 (referring to JI Initial Q103(a) rather than directly stating, again, that "[t]he Companies do not track income data on customers").
[74] LG&E/KU Resp. to JI Initial Q 109.
[75] LG&E/KU Resp. to JI Initial Q109 and JI Initial Q-103(a).
[76] Grevatt Direct at 15–16.

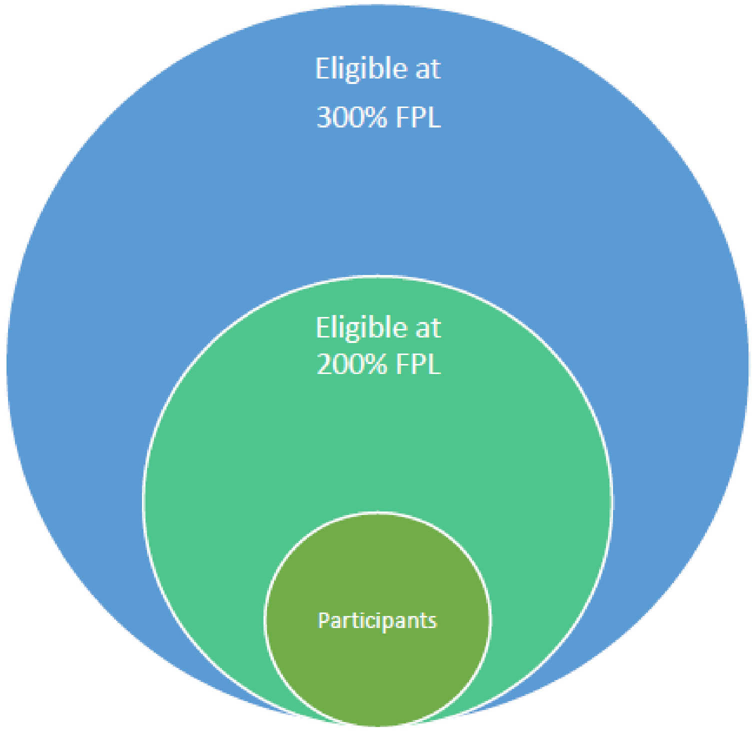
year, only 2% of eligible customers could be served each year, and it could take *decades* to reach every eligible household.[77] As Mr. Grevatt explained, without knowing the numbers, there is not any context from which to judge whether a program budget will provide a reasonable number of the Companies' most economically vulnerable households an avenue to comprehensive home energy savings.[78]

Mr. Grevatt explained the problem with arbitrarily expanding eligibility like this, which will increase the pool of eligible customers and may *reduce* the number of households below 200% FPL that are served by the program.[79] Unfortunately the Companies "fail to see the relevance" of Mr. Grevatt's illustration of these problems.[80]

Ms. Isaacson's defense of the expanded eligibility criteria is simultaneously illogical and off-point.[81] First of all, no, an expansion of eligibility criteria <u>does not</u> do anything to change the number of customers served.[82] An expansion of eligibility criteria changes the pool of eligible customers—not the number of customers served—as illustrated below.

---

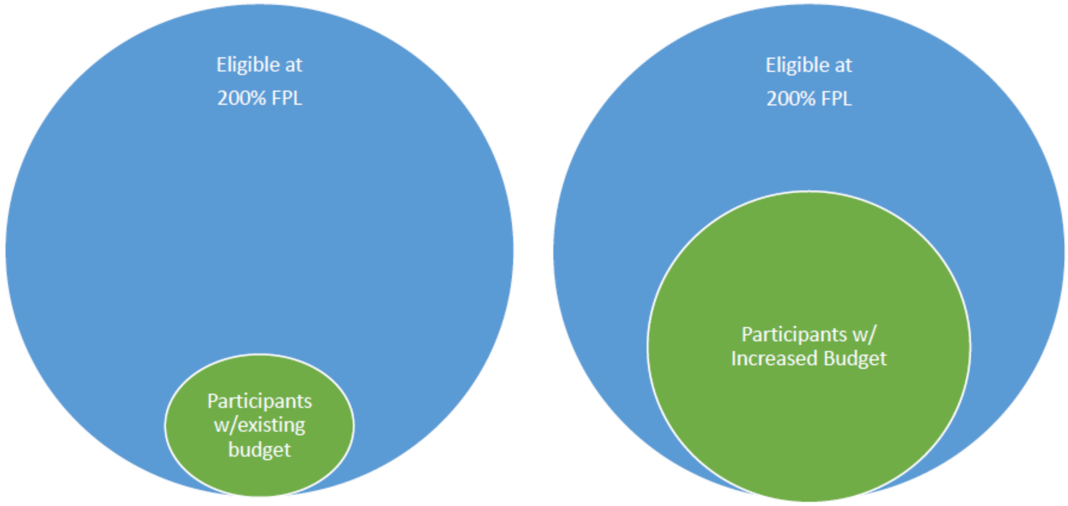
[77] Grevatt Direct at 18.
[78] *Cf.* KRS 278.285(1)(g) (reasonableness of proposed DSM/EE plan turns, in part, "[t]he extent to which the plan provides programs which are available, affordable, and useful to all customers")
[79] Grevatt Direct at 15–17.
[80] Isaacson Rebuttal at 8:16.
[81] *See also* Aug. 28, 2022 HVT at 18:37:53 to 18:38:20 (Mr. Bevington offers similarly illogical statements suggesting that expanding the pool of eligible customers will increase the number of customers served).
[82] *Contra* Isaacson Rebuttal at 8:16–18 ("The change in eligibility criteria will allow the Companies to serve more low-income customers . . . .").



Increasing the eligibility threshold does nothing to increase the number of participants served; increasing the eligibility threshold dilutes the ability to serve customers at the existing threshold, where significant unmet needs remain, absent an infusion of new resources.[83] That simple logic should be beyond dispute. A "change in eligibility criteria" does not "allow the Companies to serve more low-income customers and with a higher budget."[84] In order to "serve more low-income customers and with a higher budget," as Ms. Isaacson claims the Companies intended, only two modifications are needed: increased annual budgets and increased caps on spending per household. Again, this logic is easily illustrated:

[83] *See e.g.*, Joint Intervenors' Hearing Ex. 9, Public Comment Letter from Association of Community Ministries (Aug. 17, 2023), https://psc.ky.gov/pscscf/2022%20cases/2022-00402/Public%20 Comments//20230818_Association%20of%20Community%20Ministries%20Public%20Comment.pdf ("JI Hearing Ex. 9").

[84] Isaacson Rebuttal at 8:16–18 (illogically offering that a "change in eligibility criteria will allow the Companies to serve more low-income customers and with a higher budget per home").



In addition to testimony offered by Mr. Grevatt on this point, public comments provided in this case by the Association of Community Ministries recognize the same problem with the proposal to increase the eligibility threshold. ACM is a "Kentucky nonprofit charitable corporation comprised of thirteen independent community ministries that administer and distribute emergency assistance funds to low-income LG&E customers who cannot afford their utility bills."[85] "ACM's member ministries directly assist[] LG&E ratepayers who have received disconnection notices by making payments to LG&E sufficient to maintain service for thirty days and also by helping to reconnect customers who have been disconnected."[86] Collectively, these member ministries serve the entire Louisville Metro area, annually distribute over one million dollars to help customers pay LG&E bills, yet still "often see clients with high utility bills that the agencies do not have sufficient funds to cover."[87] What Mr. Grevatt reasonably assumed largely from experience and public data sources, ACM's experience directly serving LG&E customers confirms: "there are many more low-income customers who could benefit

[85] JI Hearing Ex. 9 at 1.
[86] *Id.*
[87] *Id.* at 2.

from weatherization and increased energy efficiency than the current capacity of the existing WeCare program allows."[88]

With many more low-income customers who could benefit from weatherization and increased energy efficiency than the existing program budget can possibly serve, Mr. Grevatt, ACM, and Joint Intervenors all conclude that the "proposed increases in the budget and participation goals are warranted . . . ."[89] All further see the harm the Companies are risking with their proposal to relax the income-qualification threshold: the possibility that "lower income [households] lose the opportunity to participate" in "the only program specifically targeted to low-income ratepayers" when they are "displaced by higher income customers."[90]

> ACM suggests that the Companies be required to track the income levels of participants on an annual basis and report the aggregate numbers to the Commission, so as to ensure that Income-Qualified Solutions continues to service customers at lower income levels. Without such tracking, there will be no way for the Companies to know whether or to what extent the addition of higher income participants is starting to limit lower income customers from the opportunity to participate in Income-Qualified Solutions. . . . Because Income-Qualified Solutions is the only program specifically targeted to low-income ratepayers, ACM would not want to see lower income clients lose the opportunity to participate in these programs.[91]

Joint Intervenors unreservedly express support for these observations from a critical stakeholder, busy providing direct services to the Companies' most economically vulnerable customers. Joint Intervenors particularly support ACM's recommendation that the Commission require annual tracking of participant incomes. That should be done as a matter of course going forward irrespective of where the income-eligibility threshold is set at the conclusion of this

---

[88] *Id.*
[89] *Id.*
[90] *Id.* at 3; *see also* Grevatt Direct at 14–15.
[91] JI Hearing Ex. 9 at 2–3; *see also* KRS 278.285(1)(g) (reasonableness of DSM/EE plan includes whether programs are "available, affordable, and useful to all customers").

case. The Companies should agree or be directed by this Commission to take the recommendation of partner organizations that help serve their highest need customers day-in and day-out.[92]

Joint Intervenors further ask the Commission to require the Companies to pursue a low-income market characterization study capable of providing a sound analytical basis for understanding the circumstances and needs of their most economically vulnerable customers, and designing and scoping programs targeted at meeting that need.[93] As an illustrative benchmark, the Companies should look to the Maryland Low-Income Market Characterization Report prepared for the Maryland Office of People's Counsel "to understand the energy affordability issues faced by Maryland's low-income population and to inform the design of existing and future programs."[94]

The Companies' proposal to significantly relax the income-qualification threshold for participation in the WeCare program is arbitrary and unreasonable and should be denied at this

---

[92] *See, e.g.*, LGE&/KU Resp. to JI Initial Q103(a). Asked to share "data used to define/determine low- and fixed-income households and how this data was used in targeting DSM-EE programs," the Companies responded that they "do not track income data on customers. The Companies partner with agencies that help to serve customers in need."

[93] Grevatt Direct at 6.

[94] Applied Public Policy Research Institute for Study and Evaluation (APPRISE), *Maryland Low-Income Market Characterization Report prepared for the Maryland Office of People's Counsel. October 2018*, at I (Oct. 2018), https://opc.maryland.gov/Portals/0/Files/Publications/Reports/APPRISE%20Maryland%20Low-Income%20Market%20Characterization%20Report%20-%20September%202018.pdf?ver=ScReQ-dA9Sk4xlj1V6bp1w%3D%3D (cited by Grevatt Direct at 6, n.2; 59, n.110). Joint Intervenors recognize that, unlike the Maryland Office of People's Counsel, the Companies are not a state agency. But that distinction makes no difference to the need for data-driven demand-side management program planning. The Companies must either stop claiming fidelity to "data driven" approaches and serving hard-to-reach customers segments with vital, cost-effective services, or invest in "understand[ing] the energy affordability issues faced by [their most economically vulnerable customers] and to inform the design of existing and future programs." *Id.*

time for the reasons explained above.[95] However the Commission decides the issue, Joint Intervenors further ask the Commission to require the Companies to pursue a low-income market characterization study and integrate quantitative data about the households they serve into future planning.[96] Reasoned, data-driven planning and implementation is needed to ensure that future DSM/EE plans will be measurably available, affordable, and useful to all customers.[97]

6. *The Commission should direct reanalysis of comprehensive home retrofit program design opportunities, including a rational analysis of PAYS.*

Joint Intervenors further recommend that the Commission direct the Companies to reassess comprehensive home retrofit program design opportunities, including a rational analysis of PAYS, and all reflecting a reasonable degree of rigor. Although the Companies agreed in their 2020 rate case "to engage in a stakeholder process through the DSM-EE Advisory Group to consider and evaluate an on-bill financing program for possible inclusion in their next DSM program plan,"[98] it was only in late 2022 that the Companies solicited such an analysis. Even then, it was an afterthought, only acted upon following reminders from DSM/EE Advisory Group participants in November 2022.[99]

---

[95] Mr. Grevatt's testimony and Joint Intervenors support other proposed changes to the WeCare program, particularly increasing the number of customers served and the allowable budget per home. Each of these changes can be reasonably expected to have the intended effect of better serving more of the Companies' most economically vulnerable customers below 200%.

[96] Grevatt Direct at 6.

[97] KRS § 287.285(1)(g) (non-exhaustively listing factors to be considered in judging the reasonableness of a DSM/EE plan, particularly including "[t]he extent to which the plan provides programs which are available, affordable, and useful to all customers").

[98] Isaacson Rebuttal at 14:17–20.

[99] Isaacson Rebuttal at 14:20–22 ("During the DSM/EE Advisory Group meetings, stakeholders expressed particular interest in a PAYS financing model and encouraged the Companies to specifically consider this model."); Joint Intervenor Hearing Ex. 7, Letter from DSM/EE Advisory Group members to LGE &K DSM Members (Nov. 10, 2022) ("JI Hearing Ex. 7") ("Regarding Energy Efficiency Financing programs, such as the Pay As You Save model, which the Commission directed LG&E-KU to evaluate in their most recent rate case, we have seen no analysis nor been engaged in any meaningful discussion.").

The result of that reminder is Ex. LI-3, a flawed six-page memo reflecting a feeble analytical attempt. First, the Companies/Cadmus appear to cherry-pick input data, and do so in a manner that was biased against finding a cost-effective solution.[100] Second, the Companies/Cadmus devise scenarios with either 100 or 1,000 participants per year, but at any scale, the first-year program administration and labor costs are identical.[101] At best, such an assumption is implausible.[102]

Third, the analysis assumes flat participation over the 2025–2030 time period.[103] This is not a realistic approach to effective program design or implementation. As the Companies do in analysis and implementation of the Residential Online Audit program and the Business Solutions program, it would be more appropriate to model increasing participation in each year.[104]

On the whole, it appears that the Companies did little "more than simply test information they are handed and shrug their shoulders."[105] The Companies' least-cost obligation demands more; it demands proactive efforts to "research, iterate, and propose cost-effective solutions to reduce energy waste through DSM-EE programs."[106] Joint Intervenors ask the Commission to direct the Companies to undertake a more rational, rigorous evaluation of whole home retrofit programs that could be implemented cost-effectively in their service territory, including an analysis of a PAYS program model.

[100] Grevatt Direct at 50:5–13.
[101] Grevatt Direct at 50:15–20.
[102] Grevatt Direct at 50:20–51:2.
[103] Grevatt Direct at 51:4–5 (citing Ex. JB-3 at 3).
[104] Grevatt Direct at 51:4–16.
[105] Grevatt Direct at 51:11–12.
[106] Grevatt Direct at 51:12–16.

7. *The Companies should fully assess costs and benefits of energy-saving programs, including non-energy benefits.*

Joint Intervenors encourage the Commission to direct the Companies to perform more comprehensive assessments of DSM/EE program costs and benefits. Contrary to the Companies' offered concern, there is no jurisdictional or other barrier forbidding them from accounting for energy savings benefits to public health, the environment, and various other categories of value marginalized as "non-energy benefits" in DSM/EE speak.[107] To the extent past orders by this Commission state otherwise, they should be revisited.[108]

Jurisdiction concerns the Commission's power to exercise its statutorily-granted regulatory authority. The delivery of adequate, reliable, and affordable energy services is the Commission's principal obligation, with authority to regulate the conduct of public utilities in providing those services. Unquestionably, the Commission enjoys jurisdiction to scrutinize utility DSM/EE plan proposals and to take relevant evidence, in this instance meaning facts and expert opinions that tend to make it more or less likely that a DSM/EE proposal is reasonable and consistent with least-cost planning.

Equally settled, cost-effectiveness tests have historically been not only relevant in Commission evaluation of DSM/EE proposals, but also given great weight.[109] Shortly before the

---

[107] *Cf.* Bevington Direct at 11:6–12:5.

[108] *See, e.g.*, Case No. 2017-00441, *In the Matter of Electronic Joint Application off Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Order at 28 (Ky. P.S.C. Oct. 5, 2018) (disclaiming the ability to hear evidence on environmental, health, or other impacts of utility rates and services with regard to DSM/EE programs upon observing that the Commission does not have jurisdiction to regulate the environment or public health).

[109] Case No. 1997-00083, *In the Matter of The Joint Application of the Members of the Louisville Gas and Electric Company Demand-Side Management Collaborative for the Review, Modification, and Continuation of the Collaborative, DSM Programs, and Cost Recovery Mechanism*, Order at 20 (Ky. P.S.C. Apr. 27, 1998) ("Any new DSM program or change to an existing DSM program shall be supported by . . . [t]he results of the four traditional DSM cost-benefit tests [*i.e.*, Participant, Total Resource Cost, Ratepayer Impact, and Utility Cost Test].") ("Case No. 1997-00083 4-27-1998 Order").

turn of the century, for example, in LG&E/KU's 1997 DSM/EE plan proceeding, Case No. 1997-00083, the Commission considered evidence of how DSM/EE programs scored on each of four cost-effectiveness tests in the "industry-standard"[110] California Standard Practice Manual.[111] The Companies, however, misunderstand that precedent and take a too narrow view of the Commission's authority. The Commission's 1997 Order in Case No. 1997-00083 also observed that the Commission had not previously "established any one of the traditional DSM cost/benefit tests as the primary determinant of whether a proposed DSM program should be approved,"[112] making it understandable that some confusion about what was required had developed.[113]

But the Commission said nothing to limit the scope of appropriate evidence that can be offered to establish the reasonableness of DSM/EE proposals, with respect to cost-effectiveness tests or otherwise. Quite the opposite, the order notes the benefit of having a broad view of approaches to considering proposed programs: "Having all four test results available has in fact provided a broad view of the potential impacts of a proposed program."[114]

As it did then, the authorizing statute provides the Commission with broad authority to take evidence on the reasonableness of DSM/EE proposals.[115] The non-exhaustive list of factors that may be considered by the Commission explicitly includes evidence of "costs and benefit analysis *and other justification*" for specific programs and measures.[116] (Emphasis added). The

---

[110] Bevington Direct at 11:13.
[111] Case No. 1997-00083, April 27, 1998 Order at 20.
[112] *Id.* at 17.
[113] *Id.* (explaining that, at the time, Principles adopted by the DSM Collaborative prescribed used of the Total Resource Cost Test and the Ratepayer Impact Test; but both LG&E and the Collaborative represented that the Participant Test was in fact "the most relevant of all the traditional DSM cost/benefits tests"; and the Companies' 1997 proposal was supported by evidence of those three tests *and* the Utility Cost Test).
[114] *Id.*
[115] KRS 278.285(1)(b) ("The cost and benefit analysis and other justification for specific demand-side management programs and measures included in a utility's proposed plan").
[116] *Id.*

Commission has not only the jurisdiction to consider cost and benefit analyses, it has the *obligation* to do so.

As to the suggestion that the Companies cannot consider the expanded externalities of the 2001 update to the California Standard Practice Manual and cannot use the Societal Cost Test, it is simply mistaken. Hearing evidence of the costs and risks associated with the Companies' fossil generating units is the Commission's stock and trade on the supply-side, without crossing jurisdictional bounds or transmuting the Commission into an environmental regulator. In this very case, the Companies have advanced evidence detailing the daunting regulatory, environmental, and financial risks posed by carbon-emitting assets used to serve customers. Where the Companies draw the line, apparently, is at admitting that *avoiding* those costs and risks with energy *savings* has value that should be accounted for in demand-side planning.

The record of this case is replete with discussion of carbon emission risks from the Companies' generating units and associated costs and risks should be factored into supply-side planning; no one doubts the relevance of that data or would mistake the Commission for the Environmental Protection Agency for hearing it. It epitomizes capriciousness to simultaneously treat these same risks as extra-jurisdictional and forbidden when accounting for the *benefits* of avoided energy from DSM/EE programs savings.

Joint Intervenors encourage the Commission to clarify expectations in this regard. There may be reasons the Companies decline to evaluate all benefits of DSM/EE programs in their planning, but the Commission's authority to regulate DSM/EE programs should not continue among them. Consistent with past recognition that effective DSM/EE programs and avoided energy "are important now and will become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation,"[117] the Commission has always had the authority to consider the value of energy savings and avoided supply-side risk. And as former "externalities" (so-characterized due to unduly narrow conception of jurisdiction and relevance), historically have become internalized (and usually at higher cost) through regulatory mandate and risk analysis, it is time to embrace a more realistic and comprehensive approach to assessing and weighing the full scope of risks and benefits attendant to utility selection and Commission approval of supply and demand-side portfolios.

8. *If the Commission approves a seven-year DSM/EE plan period, a mid-plan update should be required by order.*

The Companies have so much to accomplish, and such a modest track record with respect to DSM planning and implementation, that if it approves a seven-year DSM/EE plan period, Joint Intervenors ask the Commission to require a mid-plan review proceeding.

The ratepayers are best served with more frequent and certain regulatory oversight at reasonable intervals, especially during periods of quickening needs for supply-side capital investments, uncertain regulatory landscapes, cultural and political tumult, and devastating affordability challenges. If the Companies are serious in saying that they can be relied upon to

[117] *In the Matter of Application of Meade County Rural Electric Cooperative Corporation to Adjust Electric Rates*, Case No. 2010-00222, Order at 15–16 (Ky. P.S.C. Feb. 17, 2011); *see also* Case No. 2010-00204, PSC Order September 30, 13 2010 ("DSM, energy efficiency, and conservation are important now and will become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation.") *see also* Case No. 2010-00222, Meade County Rural Electric Coop. Order at 15; Case No. 2008-00408, *In the Matter of Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007*, PSC Order at 22 (Ky. P.S.C. Oct. 6, 2011).

pursue a mid-plan filing,[118] it should scarcely matter whether the Commission requires one by a date certain.[119]

Moreover, the specific timing of that mid-plan adjustment need not be set in stone, unyielding to reality. If time passes, and the Companies come to believe there is good cause to reset the deadline for a mid-plan filing originally ordered here, the Companies would of course be free to move to extend or shorten the timeline as warranted by the circumstances.

At this moment, Joint Intervenors posit that close oversight of the Companies' expanding DSM/EE Programs by this Commission can only help those programs to be more successful over time. The Commission should require the Companies to file a mid-plan update, if also approving a DSM/EE plan period that extends to 2030.

C. DSM/EE Process was unreasonable and in need of improvement.

The Companies' approach to DSM/EE planning needs immediate and lasting improvement. Reviewing the Companies' conduct over the past three years, Joint Intervenors cannot avoid the conclusion that the Companies are not taking seriously the potential to defer, reduce, and avoid more expensive investments in generation and transmission resources by serving customers with energy savings. In LG&E/KU's pursuit of two NGCCs, it appears that demand management and energy savings as strategies to defer or reduce capital projects were an afterthought.

---

[118] *See e.g.*, Isaacson Rebuttal at 12–13; *see also* Response of Kentucky Utilities Company & Louisville Gas & Electric Company to Commission Staff's Post-Hearing Request for Information, Question6 (Sept. 15, 2023) ("LGE & KU Resp. to Staff PH Q6"), Attach. 2 at 2 (November 2022 email communication from John Bevington to Advisory Group participants refusing to delay the DSM/EE proposal filing to allow time for meaningful stakeholder participation, and committing that "deploying these programs and enabling savings for our customers as soon as possible won't keep [the Companies] from exploring possible additional measures and savings . . . .").

[119] *See e.g.*, Aug. 29, 2023 HVT at 15:13:15 to 15:15:00 (discussing need for mid-plan update, including observation that "if [the Companies have] been coming in with pretty good regularity, then this is not burden on [them] whatsoever. It just provides the Commission and ratepayers with a little bit more surety that the programs are being assessed on a regular basis.").

1. *Despite growing certainty in the 2028 arrival of a need for additional capacity, the Companies did rather little to meaningfully pursue increased energy savings.*

As it turns out, treating energy savings as an afterthought in a gas plant CPCN quest is an improvement from the Companies' approach in their most-recent long-range integrated resource plan, where DSM/EE programs were simply ignored. In their most-recent opportunity for integrated resource planning, the Companies arbitrarily and unreasonably assumed zero incremental savings from their DSM/EE programs after 2025—the end of the then-approved plan period.[120] The Companies made this decision to sideline planning for DSM/EE programs or savings potential despite a rather certain expectation of a near-term capacity need, and analyses offering avoided cost values adjusted to account for the timing of that capacity need and DSM/EE program start years.

On this point, the 2021 IRP and witnesses' sworn discovery responses speak for themselves:

> The current DSM Portfolio is currently only approved through the end of 2025, which is why there are no projections for incremental energy and demand impacts beyond this date.[121]

Similarly, the Companies made no effort as part of the IRP to evaluate specific program options or program design as part of the IRP proceeding: "The Companies did not directly evaluate new

[120] Joint Intervenor Hearing Ex. 5, *In the Matter of Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, LG&E/KU's Resp. to JI Supplemental Request 2.73(a) (Mar. 4, 2022) ("JI Hearing Ex. 5") confirming that the 2021 IRP indicated all DSM programs ending at the end of the 2019–2025 plan period and included no projections for incremental energy and demand impacts after 2025); *cf.* KRS 278.285(1)(d) (requiring the Commission to consider whether proposed DSM/EE plan is consistent with most recent long-range IRP as part of reasonableness determination). In this particular instance, the proposed DSM/EE Plan's inconsistency with the most recent IRP makes the proposal *more* reasonable, given the categorically unreasonable approach to DSM/EE planning in the 2021 IRP.

[121] JI Hearing Ex. 5 – LGE/KU IRP Response to JI-Q 2.73 (Case No. 2021-00393).

DSM programs for this IRP."[122] By ignoring potential and pushing programs to the planning back-burner, the 2021 IRP was a squandered opportunity to take seriously the potential to serve customers with energy *savings*. It was also inconsistent with the expectation of the General Assembly, which in KRS 278.285(1)(d) makes comparison of a proposed DSM/EE Plan with the most recent IRP a criteria for reasonableness of the plan, and of the Commission, which in 807 KAR 5:058 specifically called for utility planning for additional conservation and demand-side programs.

But for the scrutiny of this Commission and its technical staff in that 2021 IRP proceeding, Joint Intervenors question whether the Companies' gas plant proposal would have been accompanied by an expanded DSM/EE Plan proposal at all. There was no outreach to the DSM/EE stakeholder group in the first half of 2022, and according to discovery responses and the Companies' May 2022 Response Comment in the IRP proceeding, the Companies expected to file their next DSM/EE plan sometime before 2025, but with no particular urgency.[123] That timing changed *after* the IRP hearing.

With the revelation at the July 2022 hearing that the Companies had pushed two NGCC self-build projects into their Generation Interconnection Queue, with CPCN applications expected by years' end, came new commitments assuring the Commission that a new DSM/EE

---

[122] Joint Intervenor Hearing Ex. 3, *In the Matter of Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, LGE/KU IRP Response to Staff 1.4 at 1 (Jan. 21, 2022) ("JI Hearing Ex. 3"). *Contra* Aug. 23, 2023 HVT at 16:36:10 to 16:39:55.

[123] JI Hearing Ex 4 – LGE/KU Response to JI 1.37(e) (Case No. 2021-00393) (Feb. 11, 2022) ("the Companies have begun to consider year-round demand-response options and will do an evaluation in preparation for the next major DSM Program Plan filing, **which is currently expected to be filed sometime before the current programs expire on December 31, 2025**.") (emphasis added); Case No. 2021-00393, *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, LGE/KU Responsive Comment at 47, n.107 (May 20, 2022) ("The Companies have committed to file their next full DSM-EE Program Plan application no later than the end of 2024 to ensure there will be no break in their DSM-EE programs."), https://psc.ky.gov/pscecf/2021-00393/kendrick.riggs%40skofirm.com/05202022112640/LGE-KU_Responsive_Comments.pdf.

Program Plan proposal would be made "close in time to, or simultaneously with, any such CPCN application."[124]

In the weeks just after those revelations and new commitments at the IRP hearing, the Companies quickly sought an updated energy efficiency potential evaluation from Cadmus,[125] and scheduled the first DSM/EE Stakeholder meeting of the year in late August.[126] But that stakeholder process was theater.

2. *The Companies witnesses did not accurately represent the perspectives of certain DSM/EE Advisory Group participants, including Joint Intervenors, on the adequacy of the DSM/EE Advisory Group process and the proposed DSM/EE Plan.*

One of the criteria for a Commission determination of the reasonableness of a proposed utility DSM/EE Plan is the "extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan[.]" KRS 278.285(1)(f). Each of the organizations comprising Joint Intervenors participated in the DSM/EE Advisory Group meetings,[127] and each has a markedly different view from the Companies on the adequacy of that Advisory Group process. Joint Intervenors' views, as presented in writing to the

---

[124] Case No. 2021-00393, *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, LG&E/KU Post-Hearing Comment at 17 (Aug. 22, 2022), https://psc.ky.gov/pscecf/2021-00393/kendrick.riggs%40skofirm.com/08222022031654/KU-LGE_Suppl_Post-Hearing_Comments_filed_8-22-22.pdf.

[125] JI Request No. 1-146(b) (asked when the Companies contracted with Cadmus to perform the potential study update presented at Ex. LI-1, LG&E/KU answered with reference to JI Request No. 1.128a); JI Request No. 1.128a (answering August 8, 2022).

[126] Bevington Direct, Ex. JB-2 (first 2022 Advisory Group meeting held on Aug. 31, 2022).

[127] JI Response to Companies' Q-1.31 (including attachments); *see also* Ex. JB-2 (reflecting participation in meeting minutes).

Companies last fall, are reflected in three letters[128] signed by a growing subset of participants that included Joint Intervenors, and others.[129] Mr. Bevington's Direct Testimony apparently intended to address those three written letters concerning the DSM/EE Advisory Group process,[130] but Joint Intervenors would dispute a suggestion that Mr. Bevington's testimony accurately addresses those three written communications.[131]

One, Mr. Bevington's testimony makes no mention that communications were written and signed by a number of organizations with no designated "spokesperson."[132] Although the letters speak for themselves, and might have been offered as evidence relevant to "[t]he extent to which customer representatives . . . have been involved in developing the plan, . . . [and] the amount of support for the plan by each participant . . .", Mr. Bevington made it sound as though there were only ephemeral one-on-one conversations.

Two, by referencing the existence of written letters, Mr. Bevington's testimony makes it appear that unidentified participants requested data and input assumptions early in the planning, and nothing more.[133] DSM/EE Advisory Group members' suggestions expressed in the written letters regarding objectives, process, opportunities, and needs went unmentioned.[134] Also unmentioned and water-under-the-bridge to the Companies: Members' concern upon being "told at the November 10 stakeholder meeting that the DSM plan is being developed in isolation from

---

[128] JI Response to Companies' Request Q-1.31, Attachment 1 (Sept. 15, 2022 Letter), Attach. 2 (November 10, 2022 Letter), Attach. 3 (Dec. 13, 2022 Letter).
[129] Additional signatories to the letters included the Homeless and Housing Coalition of Kentucky, Kentucky Interfaith Power & Light, Renewable Energy Alliance of Louisville, Louisville Metro Government, and individual participants.
[130] Aug. 28, 2022 HVT at 19:52:00 to 19:54:53.
[131] *Compare* Bevington Direct at 15–16 *and* Joint Intervenors' Response to Post-Hearing Request for Information from Kentucky Utilities Company & Louisville Gas & Electric Company, Question 1.31 (Sept. 1, 2023) ("JI Resp. to LGE & KU PH Q-1.31), Attach. 1, 2, and 3.
[132] Joint Intervenor Hearing Exs. 6, 7, and 8.
[133] Bevington Direct at 15:1–16:10.
[134] *Compare id.* and JI Hearing Ex. 6, Sept. 15, 2022 DSM/EE Advisory Group Letter.

supply planning and discussion of LG&E/KU's plans to procure new natural gas generation are out of place for the DSM group," and the signatories' observation that, in so doing, the Companies were not following Staff's recommendation from the 2021 IRP.[135]

While much was unmentioned, other mentions are not credible. In particular, Mr. Bevington's testimony persists in scapegoating a "spokesperson,"[136] an observation rebuffed by DSM/EE Advisory Group participants, in real-time during an Advisory Group meeting[137] and then again in writing:

> Regarding our request for data in September, we take issue with the Companies' attempt to blame customer representatives for LG&E-KU's failure to openly provide the information essential for collaborative participation in DSM planning. This lack of openness extends back to the most recent IRP process, in which customers and intervenors engaged in good faith, while the Companies presented "scenarios" that had no relation to the plans they were actually developing. These "actual" plans – to build two new NGCC plants – were revealed during the IRP hearings but not within the IRP documents and not to the DSM Advisory Group, despite their direct relevance to DSM planning. [138]

---

[135] JI Hearing Ex. 8, December 13, 2022 Letter from DSM/EE Advisory Group participants at 1.
[136] *See* Bevington Direct at 15:7–11 (offering hearsay statement that requested data was not provided because unidentified "spokesperson" said something directly to Mr. Bevington).
[137] *See* Attach. 2 to Resp. to PSC-PH-1 Question No. 6 at page 1 of 23 (email from Mr. Bevington to DSM/EE Advisory Group participants shortly after November 10, 2022 meeting, and implicitly acknowledging that participants voiced a different view of the history of communications on certain participants written data sharing request dated September 15, 2022, when he suggests that "[t]he history of related conversations is not as important as moving forward positively."). Of note, Joint Intervenors have never disputed the fact the Companies rushed to provide data access without further clarification following the September 15, 2022 request for data, and subject to non-disclosure agreements, some months later in mid-November. Those facts are plain. The gravamen of Joint Intervenors complaint here has always been that, by mid-November 2022, the Companies' DSM/EE Plan was already final, with no opportunity to offer feedback that might materially change or improve the Plan before the Companies' preferred filing timeline. Attach. 3 of JI's Resp. to LG&E/KU Data Request Q-1.31, December 14, 2022 Letter from DSM/EE Advisory Group participants ("While we acknowledge that LG&E-KU took steps towards making data available in mid-November (conditional upon signing of NDA's), that did not allow reasonable time for stakeholders to review and provide meaningful feedback and input if the DSM plan were to be filed in December.").
[138] JI Resp. to Companies Request Q-1.31, Attach. 3.

There surely is something that explains the Companies' decision to withhold data from the DSM/EE Advisory Group, but the excuses were not credible then, and are not credible in this proceeding.

On the one topic Mr. Bevington does mention—withholding of the data, inputs, and other assumptions used in the DSM/EE modeling and cost-testing—the Companies themselves illustrate how feasible it would have been to share that information in September. To the extent the data and information existed at the time, the Companies could have provided it as easily as they managed to once filing of their proposal was imminent, without further clarification from stakeholders.

Four, there is *still* the persistent suggestion that the data underlying DSM/EE planning could not be shared with DSM/EE Advisory Group participants due to its "confidential nature."[139] But in fact, confidentiality protections are almost entirely unnecessary in program planning.

Five, Mr. Bevington extensively discussed the non-disclosure agreement the Companies required of Adivosry Group participants to access underlying data, yet forgot to mention the concerns voiced by and written complaints from a collection of Advisory Group participants: "We do have objections to the NDA's that were proposed. As we stated previously, the NDA improperly seeks to restrict Advisory Group participants' access to a broad scope of information that should be publicly available."[140]

Lastly, Joint Intervenors unhesitatingly maintain that the Companies could not or would not share underlying data before November 2022, and as a result, stakeholders could not know or

[139] Bevington Direct at 15:17.
[140] JI Resp. to Companies Request Q-1.31, Attach. 3.

understand the data-driven reasons for different choices—to the extent there ever were any[141]—much less collaborate in weighing alternatives.[142]

Claims by employees of the Companies' service company that the DSM/EE Advisory Group supports the proposed DSM/EE Program Plan or materially contributed to its development should be viewed skeptically, if credited at all. In the least, the record reflects that Joint Intervenors dispute such claims, and were included among a subset of participants that repeatedly asked the Companies for a more rigorous and transparent process. By November, when those written requests *still* had not been answered, Joint Intervenors were among a subset of participants that asked the Companies to delay filing of this DSM/EE proposal, so that a meaningful stakeholder process could take place.[143] The Companies refused to wait and refused to revisit any aspect of their process or decision-making.[144]

D. DSM/EE Plan Conclusion

If least-cost planning is the goal, Joint Intervenors respectfully submit that the Companies need to do better when it comes to Demand-Side Management, and they need to do better yesterday. The Commission has in the past, and in the IRP regulations, noted that conservation and demand management programs are resources that should be developed in an integrated

[141] For example, there was no updated potential study information until the end of November 2022. Isaacson Direct, Ex. LI-1; LG&E-KU Resp. to Initial JI Q 146(c).
[142] KRS 278.285(1)(f) (to determine reasonableness of DSM/EE proposal, the Commission should consider "[t]he extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan[.]").
[143] *E.g.*, Attach. 2 to Response to Staff PH- Q6 at 1–2 (email communication from Mr. Bevington immediately following November 2022 Advisory Group meeting acknowledging request to delay the DSM/EE proposal filing so as to allow time for meaningful stakeholder engagement).
[144] *Id.* As hopefully reflected through Joint Intervenors discussion of DSM/EE process, Joint Intervenors dispute the claims by Mr. Bevington that the Companies "worked very hard" to listen to and respect stakeholder feedback in their DSM/EE planning process. If that were the case, the Companies would have credibly updated their stale 2016/17 potential studies and pursue cost-effective potential ages ago.

manner to best address customer needs. As the foregoing discussion retells, the Companies' lackluster planning approach led to reports of very limited value and use that understate achievable and cost-effective potential in their service territories; frayed trust with allies the Companies need to help make their programs successful; and a proposal that reflects both ambitious savings growth *but is* a mere fraction of what peer utilities consistently achieve.

At the end of the day, the least-cost, least-risk kilowatt hour is one the Companies don't need to generate and deliver. It is a weatherized building shell, no longer wasting kilowatt hours with drafts that have people reaching for blankets and space heaters. It is commercial LED lighting, and it is cold-climate heat pump technology's advancements in efficiency and capabilities in recent years.

On the whole, considering the law, record evidence, and confidence in the value of serving customers through energy *savings*, Joint Intervenors make the following recommendations to the Commission:

(1) Correct past conflations of jurisdiction and the weight of evidence, and reaffirm the Commission's jurisdiction over the DSM/EE programs of regulated utilities, including broad discretion to hear evidence on cost and benefit analyses or other justifications for proposed portfolios, programs, and measures.

(2) Direct the Companies to reassess technical and economic potential using avoided energy and capacity costs that reasonably reflect future needs, with all material inputs conspicuously and plainly disclosed on the face of the final report;

(3) As one component of that reassessment or separately, direct the Companies to conduct a low-income market characterization study to capture demographic data and characteristics of their lower-income customer segment, similar to a Maryland Low-Income Market Characterization Report prepared for the Maryland Office of People's Counsel in 2018. Like the Maryland study, the Companies' market characterization should "furnish data that can be used to understand the energy affordability issues faced by [Kentucky's] low-income population and to inform the design of existing and future programs." The findings of the study should be used to inform income eligibility criteria and the scale and scope of Income Qualified DSM-EE programs;

(4) Direct the Companies to conduct a meaningful analysis of comprehensive home retrofit program design opportunities that includes a rational analysis of PAYS. Such an analysis should work to assess the longer-term benefits of a retrofit program that ramps up to a larger number of customers and appropriately spreads startup and administration costs across them;

(5) Direct the Companies to develop a new 2024–2030 DSM-EE Plan that ramps up over the period to achieve 1.0% gross energy efficiency savings as a percent of 2021 sales by 2027 and maintains a similar level of EE savings through 2030. Program level savings should reflect an equitable balance between residential and non-residential savings opportunities.

(6) Reject the proposal to expand the WeCare/Income Qualified Solutions program income eligibility threshold, and direct the Companies to track and report data on the income of participating households, and other characteristics as appropriate.

(7) Direct the Companies to take the required steps to increase combined DLC and Bring-Your-Own Device ("BYOD") program participation to approximately 250,000 customers in total by 2030. This should be done by proactively enrolling DLC customers in BYOD to circumvent expected attrition from the program as switches fail. These customers represent a ripe target for continued participation in the Companies' demand response programs and the opportunity to retain them should not be squandered.

(8) To protect customers from the risk of the DSM-EE plan becoming out of date as circumstances change, direct the Companies to file a DSM-EE plan update in 2026, based on a potential study refresh that includes updated avoided costs and re-calculated cost-effectiveness.

III. THE COMMISSION SHOULD INTERPRET KRS 278.264 CONSISTENT WITH ITS PLAIN MEANING, STATUTORY CONTEXT, AND ESTABLISHED REGULATORY PRACTICE.

KRS 278.264[145] imposes certain obligations on the Commission relative to the retirement of "electric generating units," which in this specific context is defined as "one or more fossil-fuel fired combustion or steam generating sources used for generating electricity that deliver . . . power to the electric power grid for sale."[146] Additionally, the law creates a rebuttable

[145] 2023 Ky. Acts 652 (Chapter 118; codified at KRS 278.262 & 264).
[146] KRS 278.262 (providing definitions for use in section KRS 278.264).

presumption against retirement of fossil-fuel fired units.[147] In order to approve the retirement of a utility-owned fossil generating unit, the applicant must provide sufficient evidence to enable the Commission to make three findings:

(a) The utility will replace the retired electric generating unit with new electric generating capacity that:

   1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;

   2. Maintains or improves the reliability and resilience of the electric transmission grid; and

   3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator;

(b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law; and

(c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency.[148]

Each of these three requirements are explored further in turn below.

[147] KRS 278.264(2).
[148] KRS 278.264(2)(a)-(c).

More generally, in this case of first impression under KRS 278.264, the Commission must interpret this new law that it is charged with implementing.[149] Kentucky statutes "shall be liberally construed with a view to promote their objects and carry out the intent of the legislature."[150] The legislature's intent, however, must be considered as expressed in the plain language of an enacted statute.[151] "The particular word, sentence or subsection under review must also be viewed in context rather than in a vacuum . . .",[152] with every part of the statute given meaning within the larger statutory scheme.[153] Courts will presume the General Assembly did not intend absurd or unconstitutional results.[154] Kentucky's statutes are to be interpreted according to common usage.[155] Technical words and phrases "shall be construed according to such meaning."[156]

A. New electric generating capacity

As described above, KRS 278.264(2)(a) establishes a requirement that, prior to the retirement of a fossil fuel electric generating unit, the utility must provide sufficient evidence to

---

[149] *See, e.g., Commonwealth, ex rel. Stumbo v. Ky. PSC*, 243 S.W.3d 374, 380 (Ky.Ct. App. 2007) (courts will "afford deference to an administrative agency's interpretation of the statutes and regulations it is charged with implementing.") (citing *Board of Trustees of Judicial Form Retirement System v. Atty. Gen. of the Commonwealth*, 132 S.W.3d 770, 787 (Ky. 2003) *and Chevron v. Nat'l Res. Def. Council*, 467 U.S. 837, 843–45 (1984)).

[150] KRS 446.080(1); *Maupin v. Tankersley*, 540 S.W.3d 357, 359 (Ky. 2018) ("We liberally construe our reading of a statute with the goal of achieving the legislative intent of the General Assembly regarding the statute's purpose."); *City of Fort Wright v. Board of Trustees of Ky. Retirement Systems*, 635 S.W.3d 37, 40 (Ky. 2021).

[151] *E.g., Bd. of Trustees of Jud. Form Retirement System v. Atty. Gen. of the Commonwealth*, 132 S.W.3d 770, 786–87 (Ky. 2003) ("It is a basic principle of statutory construction that legislative intent may not be garnered from parol evidence, especially parol evidence furnished by a member of the legislature"); *see also Decker v. Russell*, 357 S.W.2d 886, 888 (Ky. 2003) (disregarding testimony from members of legislature on intent of statute as inappropriate in statutory construction).

[152] *Jefferson County Bd. of Educ. V. Fell*, 391 S.W.3d 713, 719 (Ky. 2012).

[153] *Shawnee Telecom Res., Inc. v. Brown*, 354 S.W.3d 542, 551 (Ky. 2011).

[154] *Id*.

[155] KRS 446.080(4); *Maupin*, 540 S.W.3d at 359 ("We interpret statutory terms based upon their common and ordinary meaning, unless they are technical terms.").

[156] KRS 446.080(4).

find that the retired fossil fuel unit will be replaced with new electric generating capacity that is (1) dispatchable, (2) maintains or improves reliability and resilience of the electric transmission grid, and (3) maintains the minimum reserve capacity requirement.

The phrase "new electric generating capacity" is not defined in the statute[157] and should be given its ordinary meaning. "Generating capacity" is a familiar statutory and practical term, and one that broadly includes assets capable of injecting electric energy into utility distribution and transmission grids. For example, the phrase "generating capacity" in Kentucky's net metering statute refers to distributed generation resources,[158] and frequently appears in Commission orders to include all alternatives.[159]

It would be a mistake to treat "electric generating capacity" as interchangeable with "electric generating unit."[160] First and most apparent, they are different terms and necessarily must have different meanings.[161] The legislature could have used the phrase "electric generating unit" in both instances or could have narrowly defined "new electric generating capacity," but did not do so. Instead, the legislature chose to use a distinct phrase to distinguish the generation

---

[157] SB4 defines only five terms: (1) "electric generating unit;" (2) "reliability;" (3) "resilience;" (4) "retirement" or "retired;" and (5) "utility." KRS 278.262.
[158] *See* KRS 278.466.
[159] *E.g.*, Admin. Case No. 387, *Re Kentucky Generation Capacity and Transmission System*, Order at 1, 12 (Ky. PSC Dec. 20, 2001) (pursue review and study of the need for development of "new electric generating capacity" and expressing no technology type biases and *including* firm capacity purchases); Case No. 2014-0002, *Joint Application of LG&E-KU for Cert. of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*, Order at 4–5 (Ky. PSC Dec. 19, 2014) (explaining LG&E/KU's proposal for new generating capacity via the Brown Solar Facility).
[160] KRS 278.262(1) ("Electric generating unit" is defined to mean "one (1) or more fossil fuel-fired combustion or steam generating sources used for generating electricity that deliver all or part of their power to the electric power grid for sale.").
[161] A fundamental rule of statutory construction commands that "effect must be given, if possible, to every word, clause, and sentence of a statute." *Kentucky Unemployment Ins. Comm'n v. Wilson*, 528 S.W.3d 336 (Ky. 2017); *Lexington-Fayette Urb. Cty. Gov't v. Johnson* 280 S.W.3d 31, 34 (Ky. 2009) (No part of a statute should be interpreted as "meaningless or ineffectual.").

resources that the Commission is to consider for replacement from the "electric generating units" that the Commission must evaluate for retirement.

Second, the legislature could have defined the term "new electric generating capacity," but again, chose not to, indicating that the definition is readily discernible and should be construed by the ordinary meaning of the phrase's words. Such a reading would be consistent with the practice of Kentucky courts of interpreting statutory terms based on their "common and ordinary meaning."[162]

Therefore, the Commission should impute a reasonable, plain language meaning to the phrase that allows for the consideration of any new resource capable of generating electricity. Such a reading would be consistent with constitutional and statutory background principles governing monopoly utility services in the Commonwealth and allows for flexibility in consideration of optimal replacement resources.[163]

Notably, nothing in KRS 278.262 requires that a retiring generating unit be replaced with *exactly the same amount* of new generating capacity. Rather, the statute simply requires the utility to "replace the retired electric generating unit with new electric generating capacity."[164] *Had* the General Assembly intended to require a utility to construct a 1:1 replacement of the capacity of a retiring unit, it would have so provided.[165] Had it proposed to revise the CPCN

---

[162] *Maupin v. Tankersley,* 540 S.W.3d at 359. Further, Kentucky courts routinely refer to dictionary definitions of common words. *E.g., Jefferson County Bd. of Educ.*, 391 S.W.3d at 720 ("While many words do have meanings that require little elucidation, even with relatively simple words like 'arise,' 'communicate,' and 'club,' [] this Court has routinely consulted the dictionary rather than stating our own definition of the word.").
[163] *See Shawnee Telecom Res., Inc. v. Brown*, 354 S.W.3d 542, 551 (Ky. 2011) ("We presume that the General Assembly intended for the statute to be construed as a whole, for all of its parts to have meaning, and for it to harmonize with related statutes.").
[164] KRS 278.264(2)(a).
[165] That the General Assembly contemplated that addressing capacity needs occasioned by retirement of a fossil-fuel fired generating unit could include alternatives to new unit construction, is apparent in KRS

standards to require replacement of retiring fossil-fuel fired generating unit with new capacity regardless of whether it was necessary to meet customer load and maintain appropriate reserve capacity, it could have done so, upsetting the twin standards of need and absence of wasteful duplication. The legislature did not do so. KRS 278.264 does not, in any fashion, amend or alter the standards for Commission consideration and approval of a CPCN under KRS 278.020.

Moreover, the Commission should interpret the requirement that a utility "will" replace a retired resource to mean that replacement is not required immediately in time, but rather, as made clear by subsequent statutory requirements in KRS 278.234, that utilities have an ongoing obligation to maintain generation capacity that satisfies the dispatchability, reliability and resilience, and reserve capacity requirements of the statute. The statute is silent on *when* such replacement is required, instead opting to allow both the Commission and utilities the flexibility to choose resources that are consistent with prudent least-cost planning.

To be sure, it would be absurd to read this subsection as requiring the construction, acquisition, or continued operation of unneeded generation resources. Not only would that be antithetical to KRS 278.020, which requires utilities to demonstrate need and an absence of wasteful duplication, but it would also be incompatible with the principles of least-cost and least-risk exposure that guide the entirety of Kentucky's long-range resource planning.[166]

278.264(4), which requires annual Commission reporting to the General Assembly to include the impact of any fossil-fuel fired generating unit retirements on the "[n]eed for capacity additions or expansions at new or existing facilities as a result of the retirement; and . . . [n]eed for additional purchase power or capacity reserve arrangements[.]"

[166] *See* 807 KAR 5:5058 ("KRS 278.040(3) provides that the commission may adopt *reasonable* administrative regulations to implement the provisions of KRS Chapter 278. This administrative regulation prescribes rules for regular reporting and commission review of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the *lowest possible cost* for all customers within their service areas and satisfy all related state and federal laws and regulations.").

As in this case, and the Commission's own experience, there are situations in which a utility may retire a resource without putting forth replacement generation.

For this reason, KRS 278.264(a) must not be read to require the replacement of retiring resources in all instances. To suggest that replacement generation is mandatory prior to the retirement of any electric generating unit is illogical and would lead to absurd results.

1. *Dispatchable*

KRS 278.262(2)(a)(1) requires new electric generating capacity to be "dispatchable." "Dispatchable" is undefined.[167] A dispatchable electric generating capacity resource should be understood to mean a unit capable of following dispatch instructions between economic minimum and economic maximum when (i) the unit is physically capable of producing electricity and (ii) the unit's power source is available.[168] This definition tracks both PJM and the Companies' Retirement Assessment,[169] and includes utility-scale solar, wind, storage and hybrid renewable-storage resources.[170] As Companies' correctly explain, a solar facility in full sun is dispatchable in the same way a combustion turbine with an adequate fuel supply and pressure is dispatchable.[171] The same is true of wind, which has a similar dispatchability to solar

[167] KRS 278.262.
[168] Expert Testimony of John D. Wilson on Behalf of Joint Intervenors Metropolitan Housing Coalition, Kentuckians For The Commonwealth, Kentucky Solar Energy Society and Mountain Association; *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*; Case No. 2022-00402 ("John D. Wilson Direct"), at 6.
[169] Retirement Assessment at 7.
[170] While Companies are not proposing any hybrid resources in this proceeding, it would be expeditious for the Commission to determine that the combination of dispatchable renewable (solar or wind) plants and storage is also dispatchable generation capacity. John D. Wilson Direct at 13.
[171] Retirement Assessment at 7; *see also* John D. Wilson Direct at 9.

and storage resources.[172] Certain types of Demand Side Management ("DSM") are also dispatchable.[173]

2. *"Maintains or improves the reliability and resilience of the electric transmission grid"*

a. Reliability

"Reliability" is defined in the statute[174] and can be met in a variety of ways. Reliability may be met with a "firm capacity" resource, but also with a combination of resources that continually evolve— particularly as increased market energy transactions and the cost-effectiveness of renewable resources, battery storage, and distributed energy resources are resulting in new methods of planning for and measuring reliability outcomes.[175] For example, the Companies' note that "DSM is . . . markedly more cost-effective than simple cycle combustion turbines ("SCCTs") for enhancing the reliability of these portfolios."[176] The approach the Companies used to determine this could be extended to other resources— including energy efficiency, customer sited generation or storage, and, could even be extended to determine the characteristics of resources that would help improve or meet reliability criteria such as seasonality and duration.[177]

---

[172] John D. Wilson Direct at 6–8 (Utilities and independent system operators usually classify utility-scale energy storage systems as a capacity asset and as such, recognize the contribution of battery storage to reliability).
[173] Retirement Assessment at 8 tbl.2.
[174] KRS 278.262(2) ("'Reliability' means having adequate electric generation capacity to safely deliver electric energy in the quantity, with the quality, and at a time that the utility customers demand.").
[175] John D. Wilson Direct at 17.
[176] S. Wilson SB4 Direct at 33. The Direct Testimony of Stuart A. Wilson in Case No. 2023-00122 containing the Retirement Assessment shall be referred to as "S. Wilson SB4 Direct". The direct Testimony of Stuart A. Wilson in Case No. 2022-00402 shall be referred to as "S. Wilson CPCN Direct".
[177] Direct Testimony of Anna Sommer on Behalf of Joint Intervenors, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 52 (July 14, 2023) ("Sommer Direct").

The Companies evaluated reliability based on loss of load expectation ("LOLE"), treating a LOLE of 3.57 as consistent with maintaining adequate reliability because this LOLE is aligned with the Companies' minimum reserve margin targets.[178] The Companies used SERVM to measure the reliability of replacement portfolios and determine each portfolio's LOLE metric. Although this approach could be improved upon,[179] it is reasonable and satisfies the reliability requirement of this statute.[180]

b. Resilience

"Resilience," while defined in the statute,[181] is more difficult to delineate. The Companies evaluated resilience using "start-up times, ramp rates, and range of dispatchable capacity . . . [as the] objective, established metrics the Companies can use to determine responsiveness to events affecting load."[182] While the Companies sufficiently demonstrated that their proposed portfolio would improve upon these metrics, they are not the only metrics by which resilience can be evaluated. For example, dispatchability, fuel security, grid services, and decentralization are all additional considerations that can be used to determine resilience; all of which the Companies' proposed resources improve upon in comparison to the units to be retired.[183]

---

[178] Direct Testimony of Stuart A. Wilson, Ex. SB4-1 at 13, Case No. 2023-00122 (May 10, 2023) (hereinafter "Retirement Assessment").
[179] *See* Sommer Direct at 55; John D. Wilson Direct at 15–16.
[180] *See* John D. Wilson Direct at 14–15.
[181] KRS 278.262(3) ("'Resilience' means having the ability to quickly and effectively respond to and recover from events that compromise grid reliability.").
[182] Retirement Assessment at 15.
[183] *See* John D. Wilson Direct at 25–26.

c. "Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator"

KRS 278.264(2)(a)(3) requires that replacement electric generating capacity "[m]aintains the minimum reserve capacity requirement established by the utility's reliability coordinator." The Commission has previously provided that "[r]eserve margin is the available generating capacity, minus peak demand, required in order to maintain reliable operation of the bulk power system, and to determine whether demand growth is adequately being served by planned generation and transmission additions."[184]

The statute identifies the "utility's reliability coordinator" as responsible for establishing a minimum reserve capacity requirement. However, the Companies' contracted reliability coordinator, the Tennessee Valley Authority ("TVA"), does not prescribe a reserve capacity requirement and the Companies, instead, establish their own seasonal reserve margin targets that are subject to Commission review.[185] Commission precedent has recognized and relied upon minimum reserve capacity requirements set by utilities.[186] Companies have sufficiently demonstrated the proposed replacement resources will satisfy the reserve capacity requirement.[187]

B. "The retirement will not harm the utility's ratepayers"

Consistent with the long-standing statutory mandate for lowest reasonable cost service, KRS 278.264 further requires that "[t]he retirement will not harm the utility's ratepayers by

---

[184] Case No. 2011-00235, *2011 Integrated Resource Plan of Duke Energy Kentucky, Inc*., Staff Report at 20 (Ky. PSC Feb. 21, 2013).

[185] Retirement Assessment at 17.

[186] *See, e.g.*, Case No. 2022-00314, *Electronic Application of EKPC for a (1) Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Madison County, Kentucky; and (2) Declaratory Order Confirming that a Certificate of Public Convenience and Necessity is Not Required for Certain Facilities*, Final Order at 7 (Ky. PSC Feb. 23, 2023).

[187] Retirement Assessment at 17–18.

causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law."[188] As stated above, Kentucky statutes are to be interpreted according to common usage.[189]

There are several possible interpretations of this requirement. One potential interpretation is as a requirement to compare the continued operation of the fossil fuel-fired units proposed for retirement with an alternative portfolio proposed for approval via a CPCN. Companies interpret the standard to mean that retiring the fossil-fuel units at issue and replacing them with a specific proposed portfolio of new electric generating capacity will result in a lower present value of revenue requirements ("PVRR").[190] Other testimony interprets KRS 278.264(2)(b) as requiring a comparison to the units proposed for approval via a CPCN through a rate impact analysis, and accordingly, takes issue with possible short-term impacts.[191]

A plain reading of this section requires only that the utility demonstrate that a proposed generation mix that includes retirement of electric generating units is demonstrated to be least cost. The standards provided in KRS 278.264 do not in any way modify the foundational principles of utility regulation reflected in KRS 278.030, that the rates of utilities for services provided shall be fair, just, and reasonable, and that that each utility shall furnish adequate, efficient, and reasonable service.

---

[188] KRS 278.264(2)(b).
[189] KRS 446.080(4); *Maupin v. Tankersley*, 540 S.W.3d 357, 359 (Ky. 2018).
[190] Joint Application; *Electronic Joint Application Of Kentucky Utilities Company And Louisville Gas And Electric Company For Approval Of Seven Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, at 7.
[191] *See* Testimony of Emily Medine on Behalf of the Kentucky Coal Association, Inc.; *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2022-00402, at 4, 23.

KRS 278.264 does not mandate one-to-one replacement of retired capacity, nor does it constrain the utility in utilizing any particular portfolio of owned or purchased, demand or supply-side resources. By placing an overall cost cap against which replacement capacity that is dispatchable, reliable, and resilient is to be measured, it provides a benchmark for consideration of capacity pledged against any load requirements residual to the retirement.

In addition, in the context of KRS Chapter 278, comparison of the units proposed for retirement to a proposed alternative portfolio makes the analysis similar to that already required of the Commission for a CPCN, but with an added rebuttable presumption against retirement as the starting point and a strict requirement that the retirements will not cost ratepayers more than an alternative.[192] Further, the phrase "net incremental costs to be recovered from ratepayers" is not defined by the statute and also, not in any way limited in horizon nor is any specific calculation required. For these reasons, an analysis, such as the present value revenue requirements, of alternatives showing that retirement of the units is among the options that results in the least cost to ratepayers would appear to be an acceptable option for satisfying this requirement.

[192] *See, e.g.*, Case No. 2022-00314, *Electronic Application of EKPC for a (1) Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Madison County, Kentucky; and (2) Declaratory Order Confirming that a Certificate of Public Convenience and Necessity is Not Required for Certain Facilities*, Final Order at 8 (Ky. PSC Feb. 23, 2023) ("Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication." (Citing *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965))); *see also* John D. Wilson Direct at 28.

C. "The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency"

Finally, Senate Bill 4 requires a showing that "[t]he decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency."[193]

As with KRS 278.264 subsection (2)(b), above, it is again clear that subsection (c) is separate and apart from subsection (a), discussed above. For this reason, again, the focus is on financial incentives for the proposed retirement of electric generating units, rather than those related to replacement capacity as in subsection (a).

However, if federal financial incentives for replacement capacity are to be considered to determine the overall effect of "financial incentives or benefits offered by any federal agency," the Commission should also consider the potential offset of any federal financial benefits or incentives for the continued operation of fossil fuel-fired units proposed for retirement. Further, to the extent any federal financial incentives are provided to the benefit of ratepayers rather than the utility itself, they do not implicate KRS 278.264(2)(c).[194]

---

[193] KRS 278.264(2)(c).

[194] *See, e.g.*, Direct Testimony of Lonnie E. Bellar, *Electronic Joint Application Of Kentucky Utilities Company And Louisville Gas And Electric Company For Approval Of Seven Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, at 22 (May 10, 2023). Indeed, were the statute to be interpreted otherwise it would run afoul of both the Equal Protection and Due Process provisions of Kentucky Constitution Sections 1, 2, and 3, and United States Constitutional Amendment 14, as well as Kentucky Constitution Sections 59 and 60 regarding Special Legislation by denying ratepayers the benefit of federal legislation based solely on their location within the jurisdiction of a particular utility. *See Louisville v. Klusmeyer*, 324 S.W.2d 831 (Ky. 1959), *Vision Mining, Inc. v. Gardner*, 364 SW 3d 455 (Ky. 2011), *Parker v. Webster County Coal*, 529 SW 3d 759 (Ky. 2017), *Calloway Cty. Sheriff's Dep't v. Woodall*, 607 SW 3d 557 (Ky. 2020). It may also violate the Commerce Clause (Article I, Section 8; *see Foresight Coal Sales, LLC. v. Chandler*, 60 F.4th 288 (6th Cir. 2023)), and the Supremacy Clause of the United States Constitution (Article VI, Clause 2; *see McCulloch v. Maryland*, 17 U.S. 316 (1819); *National Foreign Trade Council*, 530 U.S. 363 (2000)); as well as the Privileges and Immunities clause of the Fourteenth Amendment (*Marchie Tiger v. W. Inv. Co.*, 221 U.S. 286 (1911)).

Finally, the Commission may also want to consider other financial impacts [associated with the] of the proposed retirements in the public interest. If approved, the cost of state tax breaks will be reduced as will the financial impacts of air pollution on the health and safety costs of] people living in Kentucky and other states.[195]

D. Additional Considerations

As this will be the first opportunity for the Commission to interpret provisions of KRS 278.264, there are other issues that remain to be resolved in its application. One issue presented by the consolidation of the Companies' retirement application with the pending CPCN-DSM proceeding is the seemingly simple question of the order in which decisions on the various parts of the case should be made. The Commission may not approve a CPCN, pursuant to KRS 278.020, without a finding of need and absence of wasteful duplication,[196] but, the Commission cannot approve retirement of electric generating units without first making findings regarding "new electric generating capacity" and net incremental costs.[197] In other words, which application must the Commission decide first?

At the onset, it is important to note that the Legislature does not require a request for a CPCN to be filed simultaneously with a request to retire electric generating units. In fact, they were not filed together in the present proceeding. Instead, the cases were consolidated by this Commission only after consideration of the Companies' motion to consolidate due to similar questions of law and fact and in the interest of administrative efficiency.[198]

---

[195] John D. Wilson Direct at 35.
[196] *Kentucky Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952).
[197] KRS 278.264(2)(a) & (b).
[198] Case No. 2023-00122, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company For Approval of Fossil Fuel-Fired Generating Unit Requirements*, LG&E-KU Joint Motion to Consolidate at 1–3, (Ky. PSC May 10, 2023); Case No. 2023-00122, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company For Approval of Seven Fossil Fuel-Fired Generating Unit Retirements*, Order at 3 (Ky. PSC May 16, 2023).

Within the overall context of the statutory scheme, it is the most logical to assess, first, the request to retire electric generating units before determining whether there is sufficient need and absence of wasteful duplication to approve a CPCN, for several reasons. First, because there is not a requirement of simultaneous filing, there may not always be a specific CPCN to compare against. And, as the Commission states in their order approving consolidation in the instant matter, "[t]he need for replacement generation is predicated upon the Commission's approval of the fossil-fuel generation facility retirements under the recently enacted SB4."[199] To interpret the requirement otherwise could lead to the absurd result of requiring continued maintenance and updates, if not operation of, entirely unneeded generating capacity at a net loss to the detriment of ratepayers.[200]

Second, retirements made necessary by outside factors such as reduced demand or updated regulatory requirements may contribute to need, and need may not be known until it is determined if units should be retired. This is the ordinary series of decisions followed in utility planning and the overall statutory scheme, when forecasts are made that may show the prudency of retirements in an integrated resource plan ("IRP") before an application for a CPCN for specific replacement capacity is submitted.

Third, KRS 278.264(2)(a) uses the future tense, requiring that "[t]he utility *will* replace the retired electric generating unit with new electric generating capacity. . . " (emphasis added). In this instance, the retirement of the affected units has been demonstrated to be more cost-effective than continued operation of those units "in compliance with applicable law." Approval

---

[199] Case No. 2023-00122, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company For Approval of Fossil Fuel-Fired Generating Unit Requirements*, Order at 3 (Ky. PSC May 16, 2023).
[200] *See* John D. Wilson Direct at 29–30 (concluding that the Commission should interpret KRS 278.264 consistent with the CPCN standard of avoiding wasteful duplication).

of the requested retirements, conditional on a more robust consideration of capacity options satisfying KRS 278.020, KRS 278.030, and meeting the cost cap in KRS 278.264, is justified in this instance.

IV. THE COMPANIES' DECISIONS TO RETIRE FOSSIL FUEL FIRED GENERATING UNITS ARE WELL JUSTIFIED, REGARDLESS OF WHAT THE COMMISSION DECIDES ON THE CPCN REQUESTS

The Companies propose to retire three small-frame gas combustion turbines ("CTs") (Haefling Units 1 and 2, and Paddy's Run Unit 12) by 2025 and Mill Creek Unit 1 by 2024 because they have determined that further investment in those units would be uneconomic and that replacement resources are unnecessary. The Companies also propose to retire Mill Creek Unit 2, Brown Unit 3, and Ghent Unit 2 and replace them with the portfolio of resources for which they are requesting CPCN approval in this case. These proposed retirements reflect the economic reality of aging and depreciating assets facing ever-evolving environmental regulations.

The Companies' filings in support of the requested CPCNs, along with the other evidence in the record, demonstrate that there is a need for replacement resources due to the cost-prohibitive investments that would be required for the Companies to continue operating each of the fossil fuel-fired generating units that it seeks approval to retire under KRS 278.264. As discussed in more detail in Section VI below, the Companies have not met their burden to show that their preferred portfolio of new resources is entitled to CPCN approval in its entirety. The record evidence does show, however, that there are multiple alternative portfolios available that would cost-effectively replace the retiring fossil fuel generating units and satisfy the requirements of KRS 278.264 to overcome the rebuttable presumption against retirements. The economic advantage of retiring the fossil units at issue in this proceeding has been repeatedly shown in recent years, persists today, and will remain over the long term. Accordingly, Joint

Intervenors request that the Commission conditionally approve under KRS 278.264(1) all of the proposed fossil fuel generating unit retirements proposed in this proceeding, subject to the Companies also presenting an approvable combination of replacement resources through revised and updated applications for CPCNs and DSM requests sufficient to meet its burden of proof under KRS 278.020 and 278.285. Regardless of the specific set of replacement resources that the Commission ultimately approves, the evidence in this case is clear that the proposed fossil fuel generating unit retirements should be approved.

A. The Record Shows that there are Replacement Resources Available that Are Lower-Cost Options and Meet the Criteria for Overcoming the Rebuttable Presumption Against Retirements.

As discussed in testimony from Joint Intervenors' witness John D. Wilson (and as discussed further below with regard to specific generating units), the evidence in this case amply supports the Companies' requests under KRS 278.264. Analytically, as discussed above, the Commission should decide the retirement approval requests first, *before* reaching the issues concerning whether the specific portfolio of resources that the Companies have put forward meets CPCN requirements.[201] Notably, KRS 278.264 does *not* require the Commission only to consider the Companies' preferred portfolio of replacement resources when deciding whether to approve unit retirement requests. Rather, KRS 278.264(1) specifically allows the Commission to "approv[e] with conditions" the Companies' retirement requests, and KRS 278.264(2)(a) requires the Commission to find that the Companies "will replace" retiring electric generating units "with new electric generating capacity." Under these provisions, the Commission has the discretion to condition approval of requests to retire generating units on submittal of an adequate portfolio of replacement resources.

[201] *See supra* at Section III.

That is what the Commission should do in this case. The record evidence establishes that the proposed unit retirements are well justified. Joint Intervenors' witness John D. Wilson's testimony goes through each of the factors required under KRS 278.264(2) to rebut the presumption against retirement and shows how the evidence in the record concerning replacement resources satisfies the statutory requirements. At the same time, witness John D. Wilson makes clear that he is not taking a position on whether the Companies' CPCN requests satisfy that separate statutory standard under KRS 278.020, nor is such a determination necessary to conclude that the Companies' requested retirements should all be approved.[202] As discussed in more detail in Section VI below, the Companies have not adequately justified their requests for CPCNs for the two proposed new NGCCs, and multiple options for portfolios of replacement resources are available and should be expeditiously reviewed further by the Companies. For example, Joint Intervenors' witness Anna Sommer performed modeling showing that a portfolio of increased renewable resources plus only one new NGCC had a NPVRR difference in the capital cost sensitivity (as corrected at the hearing) of $81,887,968 and a LOLE of 0.91.[203] Additional variations on this portfolio can and should be evaluated to optimize its cost-effectiveness as a potential alternative. In addition, Louisville & Lexington and Sierra Club witness Levitt testified that joining PJM would reduce and delay the need for new capacity and result in substantial resource cost savings for the Companies' customers. Joint Intervenors' witness John D. Wilson reviews this possibility as an alternative to the Companies' proposal and concludes that reliance on PJM membership for a portion of its resource needs would equally satisfy the KRS 278.264(2) criteria.[204]

[202] John D. Wilson Direct at 28–31.
[203] Sommer Direct at 28–36.
[204] John D. Wilson Direct at 40–46.

Given the numerous flaws and deficiencies in the Companies' requests for CPCNs for the NGCC units (discussed in detail below), the Commission should conditionally approve the Companies' retirement requests and order a revised DSM/EE plan (as discussed above), but keep this docket open until the Companies have submitted an adequate set of CPCN requests for replacement resources.

B. There Is Ample Evidence that Retirement of Each of the Proposed Units Would Benefit Ratepayers.

1. *Simple Cycle Combustion Turbines*

The Companies propose to retire the three small-frame CTs—Haefling Units 1 and 2, and Paddy's Run Unit 12—upon each unit's experiencing a major mechanical issue, which the Companies assume will occur by 2025.[205] Once each of these units faces a major mechanical issue, the likely cost to repair the unit would exceed its reliability value to the Companies' system as a secondary peaking unit.[206] The Companies' initial CPCN application in this case assumed that these CTs would retire in every portfolio modeled and would not contribute to the need for any replacement resources,[207] due to the relatively low efficiency of these units and the high cost of maintaining them relative to the reliability value they provide to the Companies' system.[208]

The Commission should approve the retirement of these small-frame CTs under KRS 278.264 and make clear that immediate replacement of the resources is not required. As

---

[205] Direct Testimony of Lonnie E. Bellar, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2023-00122, at 4 (May 10, 2023) ("Bellar SB4 Direct").
[206] *Id.* at 5.
[207] Retirement Assessment at 3–4.
[208] *See* LG&E-KU Response to Staff Fourth Request Q4-11 ("[T]hese units have very high heat rates and are unreliable compared to the Companies' other resources, and they therefore operate at extremely low capacity factors.").

discussed above, KRS 278.264 does *not* require one-to-one replacement of resources as generating units retire. With respect to resources such as the small-frame CTs, where the record clearly shows that their direct replacement is unnecessary and would amount to wasteful duplication, it would be an absurd result to interpret the statute as requiring replacement resources.[209] It is important to recognize that KRS 278.264 was *added* to a statutory scheme that also includes KRS 278.030—which requires a showing of need and absence of wasteful duplication to support a request for a CPCN for new resources—and it would be inconsistent with that statutory scheme to construe KRS 278.264 to require a utility to replace a retiring unit that it otherwise would have no need to replace. Retirement of the small-frame CTs without replacing them is something that the Companies would do in the ordinary course of business; as the Companies have noted, they have retired four other small-frame CTs in the last 10 years after they experienced major mechanical issues, without replacing them.[210]

Nor does retirement of the small-frame CTs implicate any of the other concerns embodied in KRS 278.264, as the record clearly demonstrates. The Companies' Retirement Assessment demonstrates that retirement of the units has only *de minimis* impacts on the reliability, resilience, and reserve margin of the Companies' system,[211] and a small but positive benefit to customers in the form of a reduction in the NPVRR.[212]

---

[209] *See, e.g.*, *Shawnee Telecom Resources, Inc. v. Brown*, 354 S.W.3d 542, 551 (Ky. 2011) (when construing statutes, courts look to "the context of the matter under consideration" and "presume that the General Assembly intended for the statute to be construed as a whole, for all of its parts to have meaning, and for it to harmonize with related statutes").
[210] Bellar SB4 Direct at 7 n.16; *see also* Retirement Assessment at 4, n.9.
[211] Retirement Assessment at 14–18. The Retirement Assessment found, *inter alia*, that retirement of the three small-frame CTs would only result in a 0.02 increase in Loss of Load Expectation ("LOLE") for the Companies' system, *see id.* at 14, tbl.5 (difference between Portfolios 2 & 3), and a less than 1% reduction in reserve margin during both summer and winter, *see id.* at 18, tbl.7 (difference between Portfolios 2 & 3).
[212] *See id.* at 20, tbl.8 (difference between Portfolios 2 & 3).

Moreover, Joint Intervenors' witness John D. Wilson found that the Companies' comparison of the likely costs of the next future repair to the CT units' reliability value *under-valued* the benefits of retiring the CTs, because the Companies failed to factor in the likely costs of subsequent repairs due to additional major mechanical issues that the CTs would likely experience if they continued to operate.[213] LG&E-KU witness Bellar agreed with this point, caveating it only by saying that "[s]uch a second-level analysis has not been required in the Companies' actual experience" to demonstrate that retirement of small-frame CTs is cost-effective because the economics in favor of retiring such units are amply clear even without a more sophisticated analysis.[214]

No party in this case has contested the Companies' need to retire the small-frame CTs or argued that direct replacement of those resources is required. The Commission should approve the small-frame CTs' retirement under KRS 278.264, without requiring any direct replacement of those resources.

2. *Mill Creek Unit 1*

The Companies propose to retire Mill Creek Unit 1 by 2024, consistent with the Commission's prior order in the Companies' 2020 ECR case, Case No. 2020-00061. In that case, the Commission found that environmental compliance investments needed to operate Mill Creek Unit 1 after 2024 were not part of a lowest reasonable cost alternative.[215] Specifically, the Companies had demonstrated in the 2020 case that Mill Creek Unit 1 would require additional wastewater treatment equipment by 2024 to comply with Effluent Limitations Guidelines

---

[213] John D. Wilson Direct at 31:17–33:2.
[214] Bellar Rebuttal at 14.
[215] Bellar SB4 Direct at 4–5 (citing Order, Case No. 2020-00061 (Ky. PSC Sept. 29, 2020); Direct Testimony of Stuart A. Wilson, Ex. SAW-1 at 17–24, *Electronic Application of Louisville Gas And Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge*, Case No. 2020-00061 (Mar. 31, 2020)).

("ELGs"), as well as a cooling tower by 2027 to comply with Clean Water Act Section 316(b) requirements, that made further investment in Mill Creek Unit 1 no longer cost-effective.[216]

Those environmental compliance requirements are still on the books today, and the record shows that additional investments would be required to continue to operate Mill Creek Unit 1. First and foremost, to comply with the Good Neighbor Plan,[217] Mill Creek Unit 1 would have to add Selective Catalytic Reduction ("SCR") equipment by the May-September 2027 ozone season.[218] Second, the Companies also anticipate that EPA will not finalize redesignation of Jefferson County to attainment for ground-level ozone, which will result in requirements for additional air pollution reduction independent of the Good Neighbor Plan that would also likely require addition of an SCR.[219] Further, as the Companies acknowledge in their testimony, an agreement with the Louisville Air Pollution Control District sets a limit on the Mill Creek plant's

---

[216] Bellar SB4 Direct at 4–5 (citing Order, Case No. 2020-00061 (Ky. PSC Sept. 29, 2020); Direct Testimony of Stuart A. Wilson, Ex. SAW-1 at 17–24, *Electronic Application of Louisville Gas And Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge,* Case No. 2020-00061 (Mar. 31, 2020)).

[217] U.S. EPA, *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards*, 88 Fed. Reg. 36654 (Jun. 5, 2023).

[218] Bellar SB4 Direct at 4. The Companies' workpapers included with their filing in Case No. 2023-00122 the estimate that the cost of adding a SCR to Mill Creek Unit 1 is the same as the cost of adding a SCR to Mill Creek Unit 2. Ex. SB4-2, attached to S. Wilson SB4 Direct ("20230328_StayOpenSummary_0314.xlsx"). The Companies have estimated the cost of a SCR at Mill Creek Unit 2 to be $110 million. S. Wilson CPCN Direct at 4.

[219] John D. Wilson Direct at 34 (citing LG&E-KU Response to KCA Second Supplemental Q4-4 (June 27, 2023)); *see also* Exhibit LEB-2, LG&E-KU Generation Planning & Analysis, *Analysis of Generating Unit Retirement Years: October 2020*, Case Nos. 2020-00349 & 2020-00350, at 4 (Nov. 25, 2020) ("LG&E will likely be required to install additional NOx controls on MC2 such as [SCR] to . . . continue to operate the unit" if the Louisville area remains in nonattainment for the 2015 ozone standard); Rebuttal Testimony of Philip A. Imber, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 13 (Aug. 9, 2023) ("Imber Rebuttal") ("But EPA indicated this June that the application will not be approved based on 2023 air quality data, keeping the Greater Louisville area in non-attainment status."); Aug. 25, 2023 HVT at 12:53:30–12:54:30.

NOx emissions that prevents the Companies from operating both Mill Creek Units 1 and 2 simultaneously during ozone season.[220]

In addition, as discussed at the hearing, coal fired generating units such as Mill Creek Unit 1 will likely face several other environmental requirements in the coming years that would either create separate requirements (in addition to the Good Neighbor Plan) for adding an SCR at Mill Creek Unit 1 if it were to continue to operate and/or would require additional environmental capital expenditures for compliance beyond those that the Companies have already factored into their analysis.[221] These additional environmental compliance requirements include potential additional cross-state air pollution regulations and petitions, as well as the Regional Haze Rule (any one of which could independently require installation of SCR),[222] as well as proposed new greenhouse gas standards that if finalized would require 40% natural gas co-firing for existing coal units retiring between January 2032 and January 2040 and 90% carbon capture and sequestration for any existing coal units operating beyond January 2040.[223] EPA has also proposed a new rule to supplement ELG requirements—which Companies' Witness Imber described as a "doozy"—that would likely require tens of millions of dollars of additional investments at each of the Companies' existing coal units for new wastewater treatment equipment if finalized as proposed.[224] Each of these additional environmental requirements is a further cost, not reflected in the Companies' analysis, that only underscores that retirement of Mill Creek Unit 1 is a prudent step to avoid the risk of future compliance costs that will likely only further increase over time.

---

[220] Bellar SB4 Direct at 4–5 n.8; *see also* Retirement Assessment at 6, tbl.1.
[221] Aug. 25, 2023 HVT at 12:53:30–15:18:52, 15:35:00–15:37:10.
[222] Aug. 25, 2023 HVT at 12:53:30–13:40:50.
[223] *See* LG&E & KU Response to Staff Fifth Request Q2; *see also* Aug. 22, 2023 HVT at 16:33:50–16:39:06; Aug. 25, 2023 HVT at 14:21:00–14:38:24.
[224] Aug. 25, 2023 HVT at 13:49:00–14:04:14, 15:35:00–15:37:10.

Much like the small-frame CTs discussed above, the Companies' initial CPCN application in this case assumed that Mill Creek Unit 1 would retire in every portfolio modeled and would not contribute to the need for any replacement resources,[225] due to the high cost of continuing to operate the unit relative to the cost of replacement resources. The Companies had also demonstrated as part of their 2020 rate case testimony, as well as in their 2021 Integrated Resource Plan, that a 2024 retirement date for Mill Creek Unit 1 is appropriate.[226] Moreover, at this late date, it is no longer even logistically feasible for the Companies to obtain the necessary approvals and make the necessary investments to bring Mill Creek Unit 1 into compliance with all environmental requirements.[227]

Accordingly, the Commission should approve the retirement of Mill Creek Unit 1 under KRS 278.264, without requiring any replacement resources specific to that unit.

3. *Mill Creek Unit 2*

The Companies propose to retire Mill Creek Unit 2 by 2027, to avoid the costs of adding a SCR or else only operating outside of ozone season to comply with the Good Neighbor Plan.[228] The Companies estimated that adding a SCR to Mill Creek Unit 2 would cost $110 million.[229] The Companies had also demonstrated as part of their 2020 rate case testimony and their 2021

---

[225] Retirement Assessment at 3–4.

[226] Bellar CPCN Direct at 2 (citing Exhibit LEB-2 from Case Nos. 2020-00349 & 2020-00350); *see also* Exhibit LEB-2, LG&E-KU Generation Planning & Analysis, *Analysis of Generating Unit Retirement Years: October 2020*, Case Nos. 2020-00349 & 2020-00350, at 3 (Nov. 25, 2020) ("Based on current capacity and demand projections, the Companies are not planning for immediate replacement of MC1's generating capacity."); LG&E-KU Joint 2021 Integrated Resource Plan, Vol. I, *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, at p. 5-17 (Oct. 19, 2021) ("LGE-KU Joint 2021 IRP, Vol I., Case No. 2021-00393").

[227] LG&E & KU Response to Staff Fourth Request Q1.

[228] Bellar CPCN Direct at 3.

[229] S. Wilson CPCN Direct at 4.

Integrated Resource Plan, that a 2028 retirement date for Mill Creek Unit 2 is appropriate, to avoid the cost of a SCR and other capital investments needed to operate beyond 2028.[230]

In addition, all of the same additional risks of further environmental compliance costs noted above for Mill Creek Unit 1 would apply equally to Mill Creek Unit 2, including risk of a further SCR requirement due to Louisville area ozone nonattainment or other Clean Air Act regulations, risk of being required to install tens of millions of dollars of additional wastewater treatment equipment under a supplemental ELG rule, and risk of facing requirements for natural gas co-firing or carbon capture and sequestration under new greenhouse gas standards.[231] None of these risks are currently quantified or otherwise factored into the Companies' analysis, but they all further favor retirement of Mill Creek Unit 2.

The Companies' modeling for this case further demonstrates that retirement of Mill Creek Unit 2 benefits customers on a NPVRR basis, without substantial impact on system reliability. For example, in response to the Commission's post-hearing data requests, the Companies modeled two portfolios in which the only difference between the two was the retirement of Mill Creek Unit 2.[232] The result was only a 0.53 increase in full year LOLE, and an [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] when updated NGCC bid information is incorporated.[233] As long as the Companies' overall portfolio maintains sufficient reliability and resilience across their system, retirement of Mill Creek Unit 2 clearly satisfies the "will not harm ratepayers" standard

---

[230] Bellar CPCN Direct at 2–3 (citing Exhibit LEB-2 from Case Nos. 2020-00349 & 2020-00350); *see also* Exhibit LEB-2, LG&E-KU Generation Planning & Analysis, *Analysis of Generating Unit Retirement Years: October 2020*, Case Nos. 2020-00349 & 2020-00350, at 5, 10 (Nov. 25, 2020); LG&E-KU Joint 2021 IRP, Vol. I, Case No. 2021-00393, at p. 5-17.
[231] Aug. 25, 2023 HVT at 12:53:30–15:18:52, 15:35:00–15:37:10.
[232] *See* LG&E-KU Response to Staff Post-Hearing Q 20 (portfolios (b) and (d)).
[233] *See id.* at Attachment 1 CONFIDENTIAL.

of KRS 278.264 and is in customers' best interests. The increase in LOLE due to retirement of Mill Creek Unit 2 can be offset by addition of other cost-effective resources; for example, according to the Companies' Retirement Assessment, addition of the Companies' self-owned solar resources would result in a reduction of 0.45 in full year LOLE, whereas the addition of the proposed solar PPAs would result in a reduction of 0.17 in full year LOLE.[234] Accordingly, given the significant benefits to customers of retiring Mill Creek Unit 2, the Commission should conditionally approve its retirement subject to the Companies submitting approvable CPCN requests for replacement resources.

4. *Brown Unit 3*

The Companies propose to retire Brown Unit 3 to avoid the costs of a $26 million overhaul that would be required for the unit to operate beyond 2027.[235] The Companies had also demonstrated as part of their 2020 rate case testimony and 2021 Integrated Resource Plan, that a 2028 retirement date for Brown Unit 3 is appropriate to avoid these costs.[236] Although Brown Unit 3 already has a SCR, it would be subject to other environmental compliance risks facing the Companies' existing coal units, including the risk of tens of millions of dollars of additional wastewater treatment equipment being required under a supplemental ELG rule, and risk of facing requirements for natural gas co-firing or carbon capture and sequestration under new

[234] Retirement Assessment at 14, tbl.5. The Companies' self-owned solar can be evaluated by comparing Portfolio 5 with Portfolio 6. The proposed solar PPAs can be evaluated by comparing Portfolio 7 with Portfolio 8.

[235] Bellar CPCN Direct at 3; S.Wilson CPCN Direct at 4.

[236] Bellar CPCN Direct at 2 (citing Exhibit LEB-2 from Case Nos. 2020-00349 & 2020-00350), *see also* Exhibit LEB-2, LG&E-KU Generation Planning & Analysis, *Analysis of Generating Unit Retirement Years: October 2020*, Case Nos. 2020-00349 & 2020-00350, at 5–6, 10–11 (Nov. 25, 2020); LG&E-KU Joint 2021 IRP, Vol. I, Case No. 2021-00393, at p. 5-17.

greenhouse gas standards.[237] Neither of these risks is quantified or otherwise factored into the Companies' analysis in this case.

The Companies' modeling does not evaluate the retirement of Brown Unit 3 independent of replacement resources, but Portfolio 2 of the Companies' Retirement Assessment evaluates retirement of Brown Unit 3 and its replacement with a NGCC unit (Brown Unit 12).[238] The Companies modeling found that this portfolio reduced full year LOLE by 0.28 and significantly reduced NPVRR in all scenarios.[239] In addition, in the portfolio modeled by Joint Intervenors' witness Anna Sommer, Brown Unit 3 is retired with only one NGCC and additional renewables added, with an overall LOLE of 0.91 and a NPVRR difference in the capital cost sensitivity (as corrected at the hearing) of $81,887,968.[240]

Given the significant benefits to customers of retiring Brown Unit 3, the Commission should conditionally approve its retirement subject to the Companies submitting approvable CPCN requests for replacement resources.

5. *Ghent Unit 2*

The Companies propose to retire Ghent Unit 2 by 2028, to avoid the costs of adding a SCR or else only operating outside of ozone season to comply with the Good Neighbor Plan.[241] The Companies estimated that adding a SCR to Ghent Unit 2 would cost $126 million.[242] In addition to the Good Neighbor Plan, other Clean Air Act requirements could compel installation of a SCR at Ghent Unit 2, including other cross-state air pollution regulations and petitions,

[237] Aug. 25, 2023 HVT at 12:53:30–15:18:52, 15:35:00–15:37:10.
[238] Retirement Assessment at 10, tbl.3.
[239] *Id.* at 14, tbl.5; 20, tbl.8.
[240] Sommer Direct at 28–36.
[241] Bellar CPCN Direct at 3.
[242] S. Wilson CPCN Direct at 4.

and/or the Regional Haze Rule.[243] The Ghent plant is approximately fifty-nine miles from Louisville and just outside the Louisville ozone nonattainment area, so it is also possible that it would be required to reduce its emissions to address Louisville's nonattainment, although the Companies are not aware that any source apportionment modeling has been done to evaluate the plant's impact on Louisville's nonattainment.[244] Ghent Unit 2 would also be subject to the risk of tens of millions of dollars of additional wastewater treatment equipment being required under a supplemental ELG rule, as well as the risk of facing requirements for natural gas co-firing or carbon capture and sequestration under new greenhouse gas standards.[245]

The Companies' modeling in this case demonstrates that Ghent Unit 2 is economic to retire without any incremental replacement resources.[246] The Companies evaluated retirement of Ghent Unit 2 individually in Portfolio 5 in their Retirement Assessment, as compared with continuing to operate Ghent Unit 2 with a SCR beginning in 2027 (Portfolio 3) or only operating Ghent Unit 2 in non-ozone season beginning in 2028, without adding a SCR (Portfolio 4).[247] The Companies found that retirement of Ghent Unit 2 results in net costs savings vis-à-vis its continued operation with a SCR in every scenario, and in only one of the scenarios (High Gas/Low CTG) a slight preference ($7 million NPVRR difference) for continued operation of Ghent Unit 2 during non-ozone season without a SCR.[248] Taken overall (and with the caveat that these numbers do not factor in Ghent Unit 2's likely additional future environmental compliance costs noted above), this demonstrates that retirement of Ghent Unit 2 is in the best interest of

[243] *See* Imber Rebuttal at 10–14; Aug. 25, 2023 HVT at 12:53:30–13:40:50.
[244] Aug. 25, 2023 HVT at 12:56:00–12:56:57, 15:26:00–15:28:59.
[245] *Id.* at 12:53:30–15:18:52, 15:35:00–15:37:10.
[246] John D. Wilson Direct at 31 (citing Retirement Assessment at 20, tbl.8).
[247] Retirement Assessment at 6, 10 tbl.3.
[248] John D. Wilson Direct at 31 (citing Retirement Assessment at 20, tbl.8).

customers and that maintaining it in operation is likely to increase customer costs.[249] Although the Companies found that retirement of Ghent Unit 2 would increase full year LOLE by 1.07 as compared with its continued operation with a SCR, as noted above, this increase can be offset by addition of other cost-effective resources; for example, addition of the Companies' self-owned solar resources would result in a reduction of 0.45 in full year LOLE, whereas the addition of the proposed solar PPAs would result in a reduction of 0.17 in full year LOLE.[250]

Further, the Commission should reject the notion advanced by intervenor KIUC that it may be economic for the Companies to continue to operate Ghent Unit 2, even though it is more expensive than alternative scenarios, and even if there is excess capacity that is not needed to serve the Companies' native load.[251] KIUC witness Kollen does not attempt to dispute that retirement of Ghent Unit 2 is a lower-cost option; rather, he concedes that its continued operation would have a NPVRR penalty of between $71 and $77 million in scenarios where a SCR is added and a penalty of between $117 and $218 million in scenarios where the unit runs only in non-ozone season with no SCR.[252] As LG&E-KU witness Bellar noted, the Companies' "stress test" modeling incorporating proposed new greenhouse gas standards shows that the only scenario in which Ghent Unit 2 would be cost-effective to operate with a SCR would be if the proposed NGCCs are limited to a 50% capacity factor *and* existing coal and gas units have a net

---

[249] *Id.*
[250] Retirement Assessment at 14, tbl.5. Retirement of Ghent Unit 2 can be evaluated by comparing Portfolio 3 with Portfolio 5. The Companies' self-owned solar can be evaluated by comparing Portfolio 5 with Portfolio 6. The proposed solar PPAs can be evaluated by comparing Portfolio 7 with Portfolio 8.
[251] *See* Direct Testimony of Lane Kollen on Behalf of Kentucky Industrial Utility Customers, Inc., *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 10–15 (July 14, 2023) ("Kollen Direct"). Notably, although KIUC opposes the Companies' request to retire Ghent Unit 2, KIUC does not oppose any of the Companies' other requests for retirement of fossil fuel generation units under KRS § 278.264.
[252] *Id.* at 11–13.

zero cost of compliance with the EPA's proposed greenhouse gas standards.[253] As witness Bellar acknowledged at the hearing, however, this is an implausible scenario: there are numerous cost uncertainties and risks associated with existing coal units' ability to comply with new greenhouse gas standards; the Companies "don't think it's going to be free" to comply with them, even with tax credits for carbon capture and sequestration factored in.[254] Similarly, witness Bellar noted that "operating Ghent 2 in the non-ozone season months through 2034 increases the net present value of revenue requirements in all fuel price scenarios the Companies studied."[255] And all of this, of course, is without factoring in the additional environmental costs that Ghent Unit 2 will likely face in the coming years, as Mr. Bellar himself acknowledges.[256]

Rather than attempting to argue that retention of Ghent Unit 2 would reduce costs to ratepayers (which they cannot), KIUC instead asserts that continuing to operate the unit "provides significant optionality over the next several years" by allowing the Companies to make off-system sales from Ghent Unit 2 when economic to do so and also consider selling the unit to another utility, such as Kentucky Power.[257] The benefits of this strategy are speculative at best, and unsupported by the record: "there is no reason to take on such a risk that could adversely affect customers," as LG&E-KU witness Bellar noted in his rebuttal testimony.[258] As Joint Intervenors' witness John D. Wilson pointed out, "[t]he necessity to review the prudence of

---

[253] Bellar Rebuttal at 15.
[254] Aug. 22, 2023 HVT at 16:33:50–16:39:06.
[255] Bellar Rebuttal at 16; *see also* Ex. DSS-2 at 1–2 to the Rebuttal Testimony of David S. Sinclair, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402 (Aug. 9, 2023) ("Sinclair Rebuttal").
[256] *See* Bellar Rebuttal at 16 ("[E]ven if the Companies could comply with the GNP by operating Ghent 2 in just certain months, there may be other EPA requirements that could drive a retirement decision for Ghent 2 based on EPA's semi-annual regulatory agenda.").
[257] Kollen Direct at 14–15.
[258] Bellar Rebuttal at 16.

continued operation of a power plant is driven by the good regulatory practice of avoiding wasteful duplication," i.e., one of the resource planning standards integral to CPCN decision-making.[259] Applied here, that principle counsels against requiring the Companies to operate Ghent Unit 2, essentially, as if it were a merchant plant, with ratepayers on the hook to cover the risks of this strategy. At most, the Commission should, as part of conditionally approving the retirement of Ghent Unit 2, encourage the Companies to consider selling the unit: as noted by Joint Intervenors' witness John D. Wilson, "[i]f there is no market for the surplus plant, that is further evidence that it is not cost-effective for the Companies to keep the plant in service."[260] And even if it turns out that there is a market for the unit, it is more appropriate for the Companies as regulated utilities to sell the unit to an independent power producer than to retain excess capacity.[261]

Accordingly, regardless of which portfolio of replacement resources that the Commission ultimately approves under the CPCN standard, the Commission should conditionally approve the retirement of Ghent Unit 2 under KRS 278.264 subject to the Companies submitting sufficient CPCN requests for replacement resources.

V. CPCN LEGAL STANDARD

A certificate of public convenience and necessity ("CPCN") must be obtained from the Commission prior to the construction or acquisition of any facility seeking to be used in providing utility service to the public.[262]

---

[259] John D. Wilson Direct at 30.
[260] *Id.* at 29.
[261] *Id.*
[262] KRS 278.020(1)(b) (Upon filing of an application for a certificate, the Commission may issue the certificate, refuse to issue, or issue in part and refuse in part).

To obtain the requested certificates for new gas, solar, and storage resources, the Companies must demonstrate a "need" for such facilities and show an "absence of wasteful duplication" resulting from each resource addition.[263]

In other words, a determination of public convenience and necessity requires both "a finding of the need for a new service system or facility from the standpoint of service requirements, and an absence of wasteful duplication resulting from the construction of a new system or facility."[264] As the party seeking Commission approval in this proceeding, the Companies bear the burden of proof by clear and satisfactory evidence that both need and an absence of wasteful duplication has been sufficiently established.[265]

A. Need for new capacity and/or energy

A utility must show "that there is a demand and need for the service sought to be rendered."[266]

To establish "need," a utility must: "first [make] a showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed and operated" and second, show that "the inadequacy . . . [is] due either to substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor

---

[263] Case No. 2022-00314, *In re Electronic Application of East Kentucky Power Cooperative Inc. For A (1) CPCN For The Construction Of Transmission Facilities In Madison County, Kentucky; And (2) Declaratory Order Confirming That A CPCN Is Not Required For Certain Facilities,* Final Order at 7 (Ky. PSC Feb. 23, 2023); 807 KAR 5:001 Section 15(2) (specifies what a utility must submit with its application for a CPCN, which, among other things, includes "[t]he facts relied upon to show that the proposed construction or extension is or will be required by public convenience or necessity," "[t]he manner in detail in which an applicant proposes to finance the proposed construction or extension," and "[a]n estimated annual cost of operation after the proposed facilities are placed into service.").
[264] *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952).
[265] KRS 278.430 ("[. . .] [T]he party seeking to set aside any determination, requirement, direction or order of the commission shall have the burden of proof to show by clear and satisfactory evidence that the determination, requirement, direction or order is unreasonable or unlawful.").
[266] KRS 278.020(5).

management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service."267 It is well established that economic retirement of generating units may create a shortfall of energy or capacity sufficient to establish a need for new generating asset(s).268

B. Absence of Wasteful Duplication

The requirement to avoid wasteful duplication "embraces an excess of capacity over need, an excessive investment in relation to productivity or efficiency, or an unnecessary multiplicity of physical properties."[269] The Commission has explained that to demonstrate that a proposed facility does not result in wasteful duplication, "an applicant must demonstrate a thorough review of all reasonable alternatives has been performed." [270]

Moreover, selection of a proposal that ultimately costs more than an alternative does not necessarily amount to "wasteful duplication."[271] "All relevant factors must be balanced."[272]

For example, in approving LG&E-KU's 2014 CPCN for the construction of the Brown Solar Facility, the Commission explained that not only would the cost of construction and operation be offset by a 30% investment tax credit, but the Brown Solar Facility offered

---

[267] *Iola Cap. v. Pub. Serv. Comm'n of Kentucky*, 659 S.W.3d 563, 571 (Ky. Ct. App. 2022), review denied (Feb. 8, 2023) (quoting *Kentucky Utilities Co. v. Pub. Serv. Comm'n of Kentucky*, 252 S.W.2d at 890).

[268] *E.g.*, Case No. 2011-00375, *Joint Application Of LG&E-KU for CPCN And Site Compatibility Certificate For The Construction Of A Combined Cycle Combustion Turbine At The Cane Run Generating Station And The Purchase Of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC In Lagrange, Kentucky*, Final Order at 14–15 (Ky. PSC May 3, 2012).

[269] *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 173 (Ky. 1965).

[270] Case No. 2022-00314, Final Order at 8, *supra* n.263.

[271] *Id.* at 7; *See also Kentucky Utilities Co. v. Pub. Serv. Comm'n v. Pub. Serv. Comm'n*, 252 S.W.2d at 892 ("By what has been said in this opinion, we do not mean to say *cost* (as embraced in the question of duplication) is to be given more consideration than the need for *service*. If, from the past record of an existing utility, it should appear that the utility cannot [or] will not provide adequate service, we think it might be proper to permit some duplication to take place, and some economic loss to be suffered so long as the duplication and resulting loss be not greatly out of proportion to the need for service.").

[272] Case No. 2022-00314, Final Order at 8, *supra* n.263.

additional benefits in the form of marginal fuel-cost savings of generation it displaces, the ability to reduce potential future CO2 compliance costs, and the opportunity for Companies to gain operational experience should the economics of battery storage systems continue to improve and should future CO2 regulations enhance their value to the system.[273]

VI. CPCN APPLICATIONS FOR NGCC UNITS

The Companies' evidence in support of each NGCC unit is insufficient, and the Commission should deny the requested certificates of need and public necessity for each of the proposed NGCC builds. In Joint Intervenors' view of the evidence, the Companies have not presented a persuasive case that customers need either gas plant, that constructing both NGCCs would not result in wasteful duplication, or that another combined cycle gas plant is a necessary part of a least-cost, reliable portfolio going forward. The record's insufficiency results from inadequate and unreliable modeling analyses, failure to explore all reasonable alternatives, and failure to reasonably account for risk and potential costs to customers.

Before turning to each of these areas of concern, Joint Intervenors begin by positing that the Companies may have decided to pursue building the Mill Creek Unit 5 and Brown Unit 12 NGCCs before even beginning the 2022 Resource Assessment.

A. It is all too plausible that the Companies first decided on building two NGCCs, then went about developing a supporting analysis.

The Companies represent that their proposal to construct two new NGCCs was based on the 2022 Resource Assessment (Ex. SAW-1), which reported resource modeling performed between August and December of 2022.[274] But considered in light of the whole record, Joint

[273] Case No. 2014-00002, *Joint Application of LG&E-KU for CPCN for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*, Final Order at 12 (Ky. PSC Dec. 19, 2014).
[274] *E.g.*, S. Wilson CPCN Direct at 6; LG&E/KU Resp. to JI Initial Q 50.

Intervenors are skeptical of the accuracy of these claims and note that some evidence suggests the Companies' preferred NGCCs were selected *before* Mr. Wilson's team began working on the analysis underlying Ex. SAW-1.

Indicia of a pre-figured decision to pursue new combined cycle capacity is difficult to ignore. The single hardest fact to ignore is one brought to light by the Commission during the Companies' Joint 2021 IRP hearing: one day *before* the Companies published a Request for Proposals ("RFP") to third-parties, the Companies submitted each of the two NGCCs proposed in this proceeding to their Generation Interconnection queue.[275] Although the project engineering group developed, and bid into the RFP, four additional NGCC proposals and three SCCT proposals, those seven projects were never added to the Generation Interconnection queue.[276]

It is telling that, among nine different gas proposals, only the now-proposed NGCC projects were placed into a queue position. NGCC projects with significantly more capacity or behind different interconnection points would require their own queue position and tailored transmission studies. But no other bid from the Companies received that practical advantage—fossil-fired or otherwise. It is as though the Companies knew, by at least June 2022, that they would propose to build the units, and had identified the locations at Mill Creek Unit 5 and Brown Unit 12 for which CPCNs are requested in this proceeding.

Also troubling, the record establishes a timeline in which the Companies' Project Engineering Group secured queue positions for Mill Creek Unit 5 and Brown Unit 12, and finalized cost estimates for the NGCC RFP bids *before* they had the study that is the claimed

---

[275] LG&E-KU Resp. to Initial JI Q 15.

[276] The Companies also submitted various non-gas project bids in response to the RFP (e.g., Brown BESS), but like all the other gas bids, none of the non-gas projects were submitted to the Generation Interconnection queue with the later-proposed Mill Creek Unit 5 and Brown Unit 12 NGCC units.

basis for those estimates. Consider the following sequence of events related to the development of capital cost inputs and the Companies' preferred NGCC plants:

March 29, 2022	Companies begin discussions with HDR Engineering ("HDR")[277]
April 8, 2022	Companies and HDR execute Services Authorization for "2027 Natural Gas Combined Cycle Feasibility Study"[278]
June 21, 2022	Companies' project engineering group submits two NGCC projects to the Generation Interconnection queue—one at its Mill Creek plant and one at its E.W. Brown plant[279]
June 22, 2022	Companies issue Request for Proposals[280]
July 12, 2022	Evidentiary hearing begins for the Companies' Joint 2021 Integrated Resource Plan (Case No. 2021-00393)
August 2022	Companies' project engineering group finalizes costs for NGCC options submitted in response to the RFP[281]
October 7, 2022	HDR completes the re-named "New Generation Options Feasibility Study" ("HDR Feasibility Study")[282]

The 2022 HDR Feasibility Study is the identified basis for the Companies' NGCC cost estimates,[283] but the 2022 HDR Feasibility Study was not final until October 2022—several

[277] LG&E/KU Resp. to Supplemental JI Q 115b.
[278] Attach. to LGE/KU Resp. to Initial JI Q 26(b) (emphasis added).
[279] LGE-GIS-2022-004 *and* LGE-GIS-2022-003. LG&E/KU Resp. to Initial JI Q 15.
[280] Direct Testimony of Charles R. Schram, *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, at 1 (Dec. 15, 2022) ("Schram Direct"), Ex. CRS-1.
[281] LGE/KU Resp. to Initial JI Q 23(b).
[282] Attach. to LGE/KU Resp. to Initial JI Q 9(e).
[283] *E.g.*, Sommer Direct at 16–20.

months *after* the Companies' project engineering group submitted two 640 MW NGCCs to their interconnection queue, and prepared bids in response to the June 2022 RFP. This sequence of events is of concern both for the credibility of the Companies' IRP process and, more centrally to this proceeding, the credibility of the assessment required by the CPCN process of the reasonable alternatives for providing reasonable low-cost utility service.

Notably, the Companies did have an earlier 2013 HDR Feasibility study for an NGCC at the Brown site, and the April 2022 Services Agreement for a "**2027 Natural Gas Combined Cycle** Feasibility Study" (emphasis added) tasked HDR with "refreshing" and refining" earlier work identified only by project number.[284] It is plausible that the Companies had only an earlier vintage analysis when Mill Creek Unit 5 and Brown Unit 12 were moved in to the interconnection queue, which would explain the understated cost assumptions.[285]

Indications that the proposed NGCCs were a foregone conclusion continued during the Resource Assessment process, *see infra* Section VI, and have since.

B. The Companies' load forecast exaggerates future energy and capacity needs by unreasonably forecasting energy savings and distributed energy resource adoption potential.

With respect to the need requirement, Joint Intervenors note that, all else being equal, the Companies' load forecast appears to overstate future energy and capacity needs due to unreasonably low projections of energy savings—whether attributable to DSM/EE Programs or independently achieved by customers—and unreasonable projections of distributed energy resources ("DER") adoption.

---

[284] Sommer Direct at 18–19.
[285] *See* Sommer Direct at 15–25 (surveying data and examples suggesting that the Companies' NGCC capital cost estimates significantly understate likely actual costs).

In the following subparts, Joint Intervenors highlight the unreasonableness of the Companies' embedded assumptions concerning energy savings and DER adoption, which had the cumulative effect of exaggerating the need for new utility-scale generation.

1. *The forecasted energy savings embedded in the load forecast almost certainly understate achievable potential and the future pace of efficiency gains.*

The load forecast overstates future energy and capacity need by assuming future energy efficiency savings numbers that significantly understate achievable potential over the planning period.[286] According to the Companies, their CPCN load forecast "assumes similar energy efficiency trends" as observed over the past decade, before savings plateau in the 2040s.[287] To model the impact of the Inflation Reduction Act *and* the Companies' proposed DSM-EE Programs, the load forecast accelerates U.S. Energy Information Administration ("EIA") forecasted efficiency improvements by ten years.[288] To validate the forecast result, Mr. Jones compares the load forecast savings to estimates of savings potential in Ex. LI-1. Joint Intervenors observe multiple flaws in this overall approach, which understate achievable savings, some portion of which could be realized with a more ambitious DSM/EE plan. *See supra* Section II.

As discussed above, the Companies' potential studies are unreasonable and sure to significantly understate achievable savings potential. Even if that were not the case, the 2022 Cross-Sector Potential Study does <u>not</u> compare well to the "energy savings projected for achievable cumulative energy efficiency potential shown in Table 1" of Ex. LI-1.[289] If you were to take Ex. LI-1's projected cumulative energy efficiency potential, and add it to Witness Jones'

[286] *See* Grevatt Direct, Sec. IV at 25:14–35:8.
[287] Jones Direct, Ex. TAJ-1 at 19.
[288] *Id.* at 20.
[289] *Contra* Jones Direct, Ex. TAJ-1 at 22.

Figure 21, reflecting assumed energy savings in the load forecast, the Ex. LI-1 potential would be off the chart entirely. Compared to the 2,612 GWh of cumulative economic savings potential by 2043 (or 3,199 GWh of cumulative economic savings potential by 2035/2038) identified in Table 1 of Ex. LI-1,[290] the proposed DSM/EE plan's cumulative savings do not come close, remaining below 1,000 GWh of energy savings.[291]

As compared to the 7,525 GWh of cumulative technical savings potential by 2043 (or 8,441 GWh of cumulative technical savings potential by 2035/2038) identified in Table 1 of Ex. LI-1,[292] the total assumed cumulative energy savings embedded in the load forecast looks even more paltry and unreasonable, remaining below 2,500 GWh of savings through 2050.[293]

Moreover, as argued by Joint Intervenors and confirmed by Mr. Jones, expanding the Companies' proposed DSM/EE plan to achieve the level of savings recommended by Mr. Grevatt would *reduce* costs to customers on a PVRR basis.[294]

The record does not provide a credible or sufficient basis for the Commission to conclude that the Companies have reasonably accounted for future energy savings in the load forecast. Exhibit LI-1 certainly cannot and does not validate the assumed saving levels.

2. *The Companies' load forecast relies on unreasonable DER resource-type assumptions and unreasonable forecasted adoption rates.*

In addition to underestimating future energy savings, the load forecast exaggerates the forecasted capacity need by arbitrarily departing from the historical distributed energy resource adoption rates. The Companies' load forecast includes a singular forecast of DER additions,

[290] Isaacson Direct, Ex. LI-1, Table 1, at 6.
[291] Jones Direct, Ex. TAJ-1, Figure 21, at 22.
[292] Isaacson Direct, Ex. LI-1, Table 1, at 6.
[293] Jones Direct, Ex. TAJ-1, Figure 21, at 22.
[294] Wilson Rebuttal at 33:18–34:1 (adding the DSM/EE Program savings recommended by Mr. Grevatt to the Companies' proposed portfolios reduced the PVRR of the Companies' portfolio by $51 million).

resulting in 185 MW of additional distributed capacity by 2052. That forecast, however, is disconnected from present experience and bears little resemblance to the actual DER growth rates on the Companies' systems since 2010. Compared to historical adoption rates, the Companies' DER assumptions may understate growth over the next five years by more than half.[295]

Admittedly, the load forecast is not expected to perfectly predict actual hourly energy and demand over the coming decades. Instead, in the world of forecasting, the concern is "reasonableness," which turns not on pinpoint accuracy but the methodology, data, and assumptions.[296] A wildly inaccurate forecast might have been reasonable, if at the time of its development, it was based on the best available data, reasonable assumptions, and a methodology with widespread endorsement from experts in the field. Conversely, accurate forecast results—standing alone—cannot establish forecast *reasonableness*. The mere fact that a forecast was accurate at one time does not mean it will continue to be accurate in the future, especially if there are identifiable flaws in its data, assumptions, and/or methodology.

Here, the load forecast's incorporation of DERs is unreasonable due to reliance on unrealistic data and counterfactual conditions. First, the load forecast relies on a DER adoption rate that assumes exclusively distributed solar additions and zero behind-the-meter storage.[297] This no-storage assumption is inconsistent with Staff recommendations from the 2021 IRP[298]

[295] McDonald Direct at 11–13.
[296] Aug. 24, 2023 HVT at 16:00:20–16:01:10.
[297] Jones Direct, Ex. TAJ-1, Sec. 3.6.1.6 at 26.
[298] Jones Direct Testimony at 4–5 (quoting Staff Report Recommendation in 2021 IRP for the Companies to "expand its discussion of [distributed energy resources] to identify resources other than distributed solar that could potentially be adopted by customers and explain how and why those resources are expected to affect load, if at all"); Ex. TAJ-1, at Sec. 3.6.2 (repeating same recommendation and responding to the recommendation). But *see* Jones Direct at 4:7–9 (clarifying that the Companies did not materially change their approach to electric load forecasting since the 2021 IRP).

and immediately disconnects the load forecast from the reality that hundreds of the Companies' customers with distributed solar installations already have behind-the-meter battery storage capacity connected to the Companies' distribution networks,[299] and an untold more may have stand-alone behind-the-meter storage installations.[300] Assuming that none of these resources exist or will exist in forecasting and resource planning is unreasonable.

Next, although the Companies acknowledge that customers all weigh decisions differently, the load forecast assumptions reduce customer motivation to economic rationalism.[301] Actual customer behavior was not considered,[302] despite the simultaneous acknowledgement of the fact that many, many customers invested in DERs irrespective of the Companies' view on economically rational conduct.[303]

Even if one accepts the simplifying assumption that DER adoption will only occur if deemed economically rational or advantageous, the load forecast's DER projections would *still* be unreasonable for insufficiently accounting for utility rates. To judge possible return on investment for purposes of DER adoption rates, the Companies assumed electric rates with 2% increases year-over-year beginning in 2025, unchanging rate structure, and cessation of net

---

[299] Jones Direct, Ex. TAJ-3 Confidential Workpapers at filepath Hourly_Forecast_Updates > PV > CONFIDENTIAL_NET Metering Cust-LGE-KU 2022-OCTOBER *and* filename "CONFIDENTIAL-_NET Metering Cust-LGE-KU 2022-OCTOBER" ("customer_input" tab).

[300] *E.g.*, Aug. 24, 2023 HVT at 14:35:00–14:36:10 (re no requirement for a customer to install stand-alone battery because net load addition without solar; but not accounting for commercial customers on rates with a demand-fee)

[301] Jones Direct, Ex. TAJ-1, Section 3.6.1.2 at 23 (explaining "analysis and forecast of distributed energy resources assumes customers are economically rational and will choose the most economically advantageous form of distributed generation.").

[302] *E.g.*, Jones Direct Ex. TAJ-1, Sec. 3.6.1.2, at 23 (explaining that load forecast "further assumes that customers will invest in energy storage (battery energy storage systems) only if it is economically advantageous for them"); *id.* at 26 (historical trends show "that some customers adopted solar even when it was not clearly economical").

[303] Aug. 24, 2023 HVT at 14:43:30–14:44:15 (Re customers have different values, make investments for range of reasons).

metering service for new DER customers mid-2026.[304] The apparent intention of the 2% annual rate increases is to match inflation, but is troublingly out of step with the actual experience of inflation since 2022 and near-term expectations.[305] Moreover, the Companies' rate assumptions do not account for classes paying demand charges, make no attempt to adjust for potential rate impacts of the capital expenses and operational expenses at issue in this proceeding (or any other), say nothing about the impact of fuel cost volatility on customer decision-making, and ignore the Companies' ability to *improve* the customer value of shifting demand in-time, or self-generating, via new rate structures.

The combined effect of these oversimplifications and departures from historical experience and known trends is an overstated load forecast and exaggerated need for new centralized generation.[306] Direct Testimony from Mr. Jones illustrates what a missed opportunity this was—in terms of reasonably or accurately forecasting future energy and capacity need, and in terms of the Companies' ability to furnish adequate, efficient, and reasonable service at the least reasonable cost. As Mr. Jones summarizes, the forecasted summer and winter peaks have different trajectories, with only the winter peak continuing to increase slightly from 2027 to

[304] Jones Direct, Ex. TAJ-1 at 29–30.

[305] Federal Reserve Board, *Monetary Policy Report – March 2023* (last update Mar. 3, 2023), https://www.federalreserve.gov/monetarypolicy/2023-03-mpr-summary.htm ("Consumer price inflation, as measured by the 12-month change in the price index for personal consumption expenditures (PCE), was 5.4 percent in January, down from its peak of 7 percent last June but still well above the FOMC's 2 percent objective.").

[306] Of note, Kentucky law does not put a thumb on the scale in favor of large centralized generation assets, with the responsibility of weighing what systems best serve the public reserved to the Commission's discretion: "While it may be conceded that a large monopoly is in theory capable of rendering cheaper and more efficient service, there are other considerations that enter into the question of whether the monopoly system best serves the public interest. There has been no declaration of public policy of this state that the type of ownership that will provide the lowest rates is the only type of ownership that will be permitted to operate a utility service. Whether, in the overall public interest, competition has advantages that offset those of monopoly is a question our legislature has chosen to leave to the decision of the Public Service Commission." *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 174 (Ky. 1965) (citations omitted).

2052.[307] According to the Companies, this "reflect[s] the impacts of increasing electric heating load that are difficult to offset with increasing distributed solar generation because such peaks tend to occur in non-daylight hours."[308] Disappointingly, however, Mr. Jones seems to have entirely missed the potential for distributed storage to contribute in meeting the Companies' winter peak *and* in improving customer and grid resilience. Further discussion on this unreasonable of DERs in the Companies' resource planning continues in Section VI below.

Here, the point stands: the Companies' load forecast unreasonably underestimates growth of DERs, causing the forecast to overstate future energy and capacity needs.[309] Had the load forecast assumed DER adoption rates to continue at the rate experienced from 2010 to 2021, one would expect the addition of over 400 MW of DER capacity by 2028—more than double the Companies' assumption of 185 MW by 2052.[310]

C. The Resource Assessment modeling was inadequate, making the results an unreliable indicator of whether the proposed NGCCs reflect wasteful duplication.

Evidence in support of the Companies' selection of the proposed NGCCs is principally supported by the 2022 Resource Assessment. Through a series of modeling exercises concerning forty-three project bids offered in response to the RFP, the Companies claim to show that the preferred gas plant builds are an indispensable part of a "least cost" replacement portfolio. The record also contains a non-trivial number of reasons to question the adequacy of that evidence to show an absence of wasteful duplication, which requires thorough review of all reasonable alternatives.[311] In the following subparts, Joint Intervenors summarize the effect of the following

[307] Jones Direct at 7:9–14.
[308] Jones Direct at 7:12–14.
[309] *See* McDonald Direct at 11–13.
[310] McDonald Direct at 6, 12–13.
[311] Case No. 2022-00314, *In the Matter of Application of EKPC for a CPCN for the Construction of Transmission Facilities in Madison County*, Final Order at 8 (Ky. PSC Feb. 23, 2023).

inadequacies in the Companies' process and analysis: (i) the potential chilling of bids at the RFP stage; (ii) a limited universe of alternatives actually evaluated by modeling; and (iii) an unreasonable reliance on outdated production cost modeling software.

1. *The Resource Assessment only evaluates responses to the Companies' RFP, which may have been chilled by the Companies at two critical points.*

The 2022 Resource Assessment process evaluated replacement resources exclusively from the set of projects bid in response to the June 2022 RFP. There may not be an intrinsic problem with limiting evidence and analysis to a particular body of RFP responses when developing new assets, and certainly not from the Companies' perspective.[312] But where a regulated monopoly utility takes this approach, the ability of that RFP to attract competitive bids becomes a significant determinant of which potential options are available to the model, under what cost assumptions. In at least two respects, the Companies' approach to the RFP process begs the question of whether they effectively chilled responses from some market participants or chilled responses particularly for thermal resources.

First, the RFP reserved a critical competitive advantage to the Companies: the ability to incorporate existing plant sites and transmission system interconnection points.[313] The RFP alerted bidders on the first page that project bids must offer a "site-specific Generating Facility . . . that the Companies can designate as a Designated Network Resource ("DNR")," as defined by the Companies' Pro Forma Open Access Transmission Tariff ("OATT").[314] The RFP requirements continue to explain that, if a resource is to be directly tied to the Companies' transmission system, the project must conform with the OATT and "obtain a generation

[312] *See, e.g.*, Bellar Rebuttal at 4.
[313] Aug. 22, 2023 HVT at 02:42:54.
[314] Ex. CRS-1 at 1, 2.

interconnection agreement . . . in a timely manner." Then, critically, the RFP requirements explain "[t]hird party respondents should not assume access to, or utilization of, existing sites owned by the Companies for siting proposed project(s)."[315]

The exclusive ability of the Companies' project engineering group to use already-owned properties and existing transmission interconnection points gave their proposals a competitive advantage.[316] Every market participant can be expected to recognize that competitive advantage would have material implications for project cost and feasibility, as the Companies' own witnesses readily acknowledge:

> The Companies own the sites where generation units are planned to be retired. These sites are connected to existing transmission infrastructure, lowering the Companies' cost of land and interconnection for new units compared to potential proposals from other parties. They also provide advantages for permitting the NGCCs.[317]

Further, these material competitive advantages did not escape the Power Supply group, Project Engineering Group, or Mr. Schram, who explained that part of his job in all this was "to make sure that Mr. Wilson's group had a broad range of actionable alternatives that took advantage of existing assets the company had for customers[.]"[318]

Second, the day before publishing the RFP to third-parties, the Companies' Project Engineering Group submitted the proposed Mill Creek Unit 5 and Brown Unit 12 NGCCs to the Generation Interconnection queue of its Independent Transmission Operator.[319] It is not only plausible, but probable, that third-parties considering a bid in response to the RFP would check

[315] *Id.* at 3.
[316] *E.g.*, Aug. 24, 2023 HVT at 16:47:00–16:50:05; LGE/KU Resp. to JI 1.160d (acknowledging that "co-location of operations and maintenance resources and access to existing transmission infrastructure are advantages").
[317] Bellar Rebuttal at 9:6–10.
[318] Aug. 28, 2023 HVT at 15:18:15–15:20:27.
[319] Aug. 24, 2023 HVT at 16:45:30–16:46:27.

the Generation Interconnection queue, if only to assess the how many projects had an earlier spot and how likely it might be that they could offer a project able to "obtain a generation interconnection agreement . . . in a timely manner."[320] Every potential third-party bidder who checked the queue after reading the Companies' RFP would have seen the Mill Creek NGCC and Brown NGCC self-build proposals already ahead in the queue.

Seeing self-build NGCC projects already in the queue and recognizing the material advantages of siting such units at locations already owned by and interconnected to the Companies' transmission system, third-party developers of thermal generation projects may have been discouraged from bothering to develop and submit competing thermal bids. To the extent that third parties could be discouraged from responding to the RFP, bids submitted by the Project Engineering Group would have fewer projects to compete with, and indeed, no bidder offered new gas generation.

Although Mr. Bellar notes that "the Companies cannot invent a market or somehow create bids that were not submitted,"[321] the Companies certainly have an ability to leverage their competitive advantages in a manner that discourages competition. Without speculating further, it can at least be said that the RFP did not furnish any competing price points for the Companies' preferred NGCC builds, or any other thermal generation option.[322] Because of that, even if one is persuaded, on the basis of the record, that some type and amount of thermal replacement generation is needed, this record offers very little to discern whether the Companies' preferred gas builds would be the most reasonable or cost-effective choice.

---

[320] Ex. CRS-1 at 3.
[321] Bellar Rebuttal at 4:21–22.
[322] Sommer Direct at 15:19–21 ("While it is not atypical for all-source RFPs to receive thermal plant bids only from affiliates, this means that there are no other bids that can help ground truth potential project costs.").

2. *Though offered to support selection of the NGCCs, the Resource Assessment modeling did very little to evaluate gas plant options.*

Even if the Companies were right that some replacement thermal generation is needed, their 2022 Resource Assessment did very little to explore alternatives to Mill Creek Unit 5 and Brown Unit 12. As observed by Ms. Sommer, the Companies' Resource Assessment modeling effectively reduced the plans evaluated to a single preferred portfolio with both NGCCs.[323] Once identified in Stage One, the Companies' preferred two-NGCC portfolio was never compared to any other significantly different plan on the basis of cost and reliability.[324] Even within Stage One, the Companies' modeling approach was so narrow as to practically prefigure selection of gas generation.

Very quickly in the Resource Assessment, options narrowed. Early in the process, when considering which RFP bids to evaluate in the modeling analysis, the Companies screened out several of their gas plant bids.[325] Left for the model to evaluate were each of the Companies' now-proposed NGCC units and two SCCT options, which, like the NGCCs, were practically identical projects, but for siting at Brown or Mill Creek. Every time testimony emphasizes that the Companies' PLEXOS modeling "considers thousands of options,"[326] it must be remembered that the model can only select from among the resources offered,[327] and in this case, the model had just four thermal options:

---

[323] Sommer Direct at 4–5.
[324] Sommer Direct at 5.
[325] Ex. SAW-1 at 12; *see also* LGE/KU Resp. to JI Q 1.81(a)-(b) (explaining that proposals Nos. 100 (NGCC), 105 (NGCC), and 106 (SCCT) in Table 43 of Appendix B of Ex. SAW-1 were screened out ahead of any modeling "due to the development risk associated with necessary land acquisition"). Proposals 102 and 104, which would have doubled the NGCC capacity install at either Mill Creek or Brown, were screened out of modeling apparently due to transmission cost and gas supply assumptions. Ex. SAW-1 at 12.
[326] *E.g.*, Wilson Rebuttal at 7:16–18 ("Importantly, PLEXOS effectively considers *thousands* of potential resource portfolios before providing an economically optimized result that satisfies reliability and other constraints.").
[327] Aug. 23, 2023 HVT at 16:32:00–16:35:10.

(1) Identically sized NGCC turbines at each of Mill Creek and Brown; and

(2) Identically sized SCCTs at each of Mill Creek and Brown

After limiting the thermal options offered in the Resource Optimization modeling stage, Mr. Wilson's team pursued one optimization run under each of six fuel price scenarios, called "Stage One, Step One." In four of six cases, PLEXOS added each of the preferred NGCCs, in the other two, PLEXOS added one NGCC and added SCR to Ghent 2. From this, the Companies concluded that at least one NGCC should be locked-in to their preferred portfolio,[328] and concluded the resource optimization phase of their modeling process.

At Stage One, Step Two, the Companies moved on to evaluating twenty-two portfolios with production cost modeling runs in PROSYM.[329] Importantly, all twenty-two portfolios included either or both the Companies' preferred NGCCs.[330] By the conclusion of Stage One, the Companies locked in *two* NGCCs as their "least-cost" portfolio.[331] That decision was locked in at Stage One despite the fact that the Companies do not know the second- or third-least cost option PLEXOS considered in any of those optimization scenarios, and we do not know whether multiple portfolios performed similarly on a PVRR basis in any particular fuel price scenario. Additionally, the Companies locked in two NGCCs at Stage One without testing how the PLEXOS optimized portfolio from each fuel price scenario performed under each of the other fuel price scenarios, creating uncertainty about how robust portfolio performance might be in different futures.

---

[328] Ex. SAW-1 at 23 (first important observation from Stage One, Step One: "Adding NGCC capacity is optimal in all fuel price cases").
[329] *Id.* at 24.
[330] *Id.*
[331] *Id.* at 26–27.

It is significant that the modeling runs performed in Stages Two and Three did nothing to reexamine selection of the two NGCCs. With that, effectively, the Resource Assessment avoided meaningful comparisons of the Companies' preferred portfolio with two NGCCs to significantly different portfolios on the basis of cost and reliability.[332] While the Companies may have performed a significant number of modeling runs to develop the 2022 Resource Assessment, that modeling was structured to minimize evaluation of gas alternatives. That approach, along with failures to reasonably account for non-gas alternatives, addressed *infra*, gives the impression that the selected NGCCs were an input to the Companies' analysis, and not an object of serious scrutiny or evaluation.

3. *The Companies' failure to fully examine all reasonable alternatives courts wasteful duplication.*

The limited examination of reasonable alternatives extended beyond thermal alternatives, and beyond the 2022 Resource Assessment. Alternatives with significant potential to cost-effectively contribute to reliably meeting customer needs importantly include DSM/EE Programs, membership in competitive wholesale markets, and DERs.

As already discussed above, *see supra* Section II, while the Companies are proposing expanding DSM/EE Programs alongside their NGCC proposals, analysis of cost-effective energy savings potential was done separately, and only integrated into the 2022 Resource Assessment modeling as part of the load forecast.[333] When the Companies later applied Mr. Grevatt's

---

[332] Sommer Direct at 5.

[333] Of note, the load forecast does not directly incorporate the savings projections or associated hourly load shapes of the Companies' proposed DSM/EE plan, which were not completed until sometime in November 2022. LGE/KU Resp. to JI Initial Q 92(e). The load forecast incorporated "preliminary" DSM/EE program savings information sometime in October 2022, and the load forecast was completed later in October 2022. LGE/KU Resp. to JI Initial Q 92. Because those final projections of energy reductions with each DSM/EE program were materially unchanged from the preliminary October 2022 assumptions, the Companies determined "it was not necessary to revise the load forecast upon receiving the final numbers." LGE/KU Resp. to JI Initial Q 92(e).

program cost and energy saving forecasts to their preferred NGCC portfolio, the result was a customer savings of $51 million on a PVRR basis.[334]

As addressed in testimony sponsored by Sierra Club, the Lexington-Fayette Urban County Government, and Louisville/Jefferson County Metro Government, outside the 2022 Resource Assessment, the Companies evaluated RTO/ISO membership, and eliminated it as a less favorable option.[335] Joint Intervenors find Mr. Levitt's analysis of flaws in the Companies' RTO/ISO study persuasive, including Mr. Levitt's conclusions with respect to the benefits of reduced capacity requirements if the Companies were to join PJM, along with economic and reliability benefits. The Companies' contrary conclusion is inexplicably out of step with industry consensus on these benefits.[336]

With respect to DERs, the Companies appear not to have considered potential to develop programs that would leverage growth in behind-the-meter resources. Distributed solar was quickly dismissed as unhelpful to meeting winter-peaking. Although that same logic would not apply to distributed solar plus storage installations, which are already present and growing on the Companies system, programmatic potential to leverage those customer investments to the advantage of the system overall was also missed.[337]

Lastly, Joint Intervenors note that, because the Companies originally used an outdated version of PLEXOS, their resource optimization modeling used time sampling settings that

---

[334] The PVRR benefits of achieving 1% energy savings as recommended by Mr. Grevatt reflect system-wide cost-effectiveness, meaning even non-participating customers would be better off with greater investment in DSM/EE programs. But the PVRR benefits also miss the individual *bill* savings that thousands of participating customers would be able to access through expanded DSM/EE programs.
[335] *See generally* Testimony of Andrew Levitt on Behalf of Sierra Club, et al., *In re Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402 (July 14, 2023) ("Levitt Direct").
[336] Levitt Direct at 33–37.
[337] *See infra* Section VII.

undervalued demand response, causing it to drop out of the "least-cost" portfolios that included either or both the NGCCs.[338] The time sampling settings may also have impacted PLEXOS's ability to reasonably characterize or value the benefits of utility-scale storage.[339]

4. *The Companies' continued use of PROSYM is unreasonable and should be viewed with skepticism, to say the least.*

In addition to methodological shortcomings in the Resource Assessment, the Companies' modeling evidence suffers another foundational problem: continued reliance on outdated, unsupported production cost modeling software, PROSYM. Continued use of PROSYM is unreasonable, and the Commission should take all PROSYM evidence lightly, if accepted as credible evidence at all.

The PROSYM software has not been updated by its developer for years, since at least 2019.[340] Given the seriousness of its application here—attempting to support decisions on how to invest billions of dollars on behalf of Kentuckians—that should be unacceptable. At the most basic level, software is code, and perfecting that code is a software developer's constant occupation. Periodically, a software developer will release updates to re-write portions of code. Updates can fix glitches, patch security weaknesses, and expand and improve functionality.[341] Over time, those updates give the software a chance to stay useful and out-do the competition. But that is not occurring with PROSYM. Sometime before 2019, PROSYM's developer stopped trying to perfect the coding, and stopped trying to out-do competing production cost modeling software.

---

[338] Sommer Direct at 7.
[339] *Id.*
[340] Aug. 23, 2023, HVT at 18:09:50–18:10:00; and 18:11:30–18:14:00 (on cross-examination, Mr. Stuart Wilson acknowledges that PROSYM has been unsupported since at least 2019, though he does not know when exactly).
[341] Aug. 23, 2023 HVT at 18:06:55–18:08:20.

And yet despite the lack of any updates, LG&E/KU continues to use PROSYM. Joint Intervenors asked before, in the 2021 IRP proceeding, that the Companies move to production cost modeling software that is still supported by its developer and more capable of accurately modeling relatively novel resources, such as storage. In the Companies' specific case, they could rely on the PLEXOS license customers are already paying for and begin to use PLEXOS for both resource expansion and production cost modeling. PLEXOS "is a proven tool for computing detailed production cost, [but] the Companies have not calibrated its inputs and settings for this purpose."[342] As Joint Intervenors understand it, the Companies resist using PLEXOS' production cost capabilities, or other current production cost modeling software, because they have developed their own adjustments and tools over the years to customize PROSYM to their liking.

It may have been reasonable immediately after PROSYM was abandoned by its developer for the Companies to continue to use their own bespoke version of PROSYM over alternatives. Learning new software takes time. For example, the Companies attempted to use PLEXOS' production cost modeling modules to rebut Ms. Sommer's modeling.[343] However, the Companies' modeling witness, Mr. Stuart A. Wilson, was unfamiliar with PLEXOS's four simulation phases, and thus unable to distinguish which among those four simulation phases relate to resource optimization as opposed to production cost modeling functions.[344] Meaning, critiques related to Ms. Sommer's PLEXOS modeling settings were offered by Mr. Stuart A. Wilson without awareness that each of the four phases may use distinct settings, and without appreciation for that fact that a setting used to have a tractable problem size for purposes of resource optimization phases may be different than a setting appropriate for production cost

[342] Wilson Rebuttal at 35.
[343] *See Id.*
[344] Aug. 23, 2023 HVT at 18:36:40–18:39:50.

modeling phases.[345] Although the Companies offered PLEXOS-based production cost modeling runs on rebuttal, they have not taken the time to fully learn the ins-and-outs of that effort.

The Companies have not taken that time to explore more advanced software options despite having had years to take action in response to PROSYM dropping from the software market, despite foreseeing a real-world need for replacement generation in the 2020s, and despite the opportunity in 2021 to begin testing alternatives through their IRP process. It simply is not reasonable that the Companies still favor PROSYM and are at square one when it comes to understanding more advanced software options. Regulated electric utilities across the country have already moved from PROSYM to more current software for production cost modeling, and the Companies' modeling witness was unable to identify any utility in the country that still relies on PROSYM in resource planning.[346] LG&E-KU may be alone in still gambling with customers' money on the basis of PROSYM production cost modeling results.

D. The Companies' modeling significantly understated the likely capital cost of the preferred NGCCs, biasing results in their favor.

In Direct Testimony, Ms. Sommer observed that the Companies' assumed NGCC cost estimates were at an early stage and likely understated actual costs.[347] The Companies' witnesses may have disagreed on rebuttal,[348] but [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. The $662 million and $700 million capacity cost assumptions for the Mill Creek NGCC and Brown NGCC, respectively,[349] used throughout the Companies' testimony and modeling [BEGIN CONFIDENTIAL] [redacted]

[345] *Id.*
[346] Aug. 23, 2023 HVT at 18:21:50–18:22:20.
[347] Sommer Direct, Section III, at 12–25.
[348] Wilson Rebuttal at 32 (complaining that Ms. Sommer's higher capital cost for gas projects was not reasonable).
[349] Bellar Direct at 17:13–15.

[redacted] [END CONFIDENTIAL] as reflected in Engineering, Procurement, and Construction ("EPC") contractor bids.[350] Ms. Sommer, by contrast, applied a 30% upward adjustment in the cost sensitivity that she ran in her modeling for this case, consistent with the high side of the error band in the Companies' Class 3 cost estimate.[351] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Up to the hearing in this proceeding, the only direct prices for gas builds were allegedly based on HDR's 2022 Feasibility Study. After receiving competitive bid offers in response to the EPC RFP, it is plain that the Companies' estimates were unreasonably low, and the modeling evidence using those capital cost estimates might as well be tossed out at this point.

In the handful of days between receiving those EPC bids and responding to post-hearing data requests,[352] the Companies' post-hearing response indicates that an uncertain number of modeling runs were performed in an attempt to quantify the impact of the significant capital cost increases. The Companies represent that, looking just to the lowest initial EPC bids values, with reductions in project contingency estimates, the cost per kW would more likely be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for Mill Creek Unit 5, and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for Brown Unit 12, which the Companies smooth to a total capital cost of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. The Companies also provide certain PVRR results allegedly based on the

---

[350] LG&E/KU Resp. to JI PH Q1(a) (publicly acknowledging that EPC contractors' "initial bid amounts reduce the current calculations of net benefits of the Companies' proposed resource portfolio").
[351] Sommer Direct at 24–25.
[352] Materials produced in response to JI PH Q1 are dated September 11, 2023, and September 12, 2023, but the post-hearing response does not appear to state when precisely the Companies received those bid materials. Whether received on September 11th or 12th, the Companies had just a handful of days before post-hearing responses would be due Friday, September 15, 2023.

updated cost values, then develop certain PVRR results based on the portfolios in Table 8 of Exhibit SB-4.[353] Granular PVRR results for each fuel price scenario are not disclosed, with the Companies' post-hearing response favoring identification of each portfolio's range of PVRRs across the various fuel price scenario, and average PVRRs.[354]

While Joint Intervenors appreciate that the Companies have, at long last, provided more developed and credible capital cost estimates based on the EPC RFP bids, a high-level narrative report of modeling results undertaken quickly sometime last week should be given no weight. The Companies simply have not provided enough information to adequately support this modeling. The narrative response does not identify the model (or models) used for those modeling runs, and the Companies did not convey any modeling input or output files confirming their narrative response. Given the short period of time the Companies had to prepare this post-hearing response, it is plausible that no additional PLEXOS or PROSYM modeling was performed before attempting to calculate PVRR impacts. It may be the case that the PVRR numbers reflect a spreadsheet analysis, using the Companies' financial workpapers.[355]

Even had the Companies offered underlying modeling files (to the extent they exist), there would not have been sufficient time for expert peer review, nor a procedural opportunity to offer new factual evidence from third-party reviewers.

Further, the Companies' narrative response offers no sworn statement to confirm that the updated PVRR results included *only* updated NGCC capital costs, and no other changes. In order to confirm that only the NGCC capital costs were updated, intervenors and the

---

[353] LG&E-KU Resp. to JI PH Q1(a).
[354] *Id.*
[355] Given the short period of time the Companies had to prepare this post-hearing response, it is plausible that no additional PLEXOS or PROSYM modeling was performed before attempting to calculate PVRR impacts.

Commission would need modeling files or an opportunity to develop facts through discovery and examination of witnesses.

Taking the updated PVRR values at face value, the Companies do not provide enough detail to reasonably interpret the significance of the PVRR changes. For one thing, there are no indications from the narrative response that the Companies updated capital costs for purposes of repeating their Stage One, Step One PLEXOS resource optimization modeling. Without revisiting portfolio optimization based on updated NGCC capital cost assumptions, the Companies will have done nothing to test if the increased capital costs would have favored different portfolio compositions than it did previously.

Also hampering the ability to contextualize the alleged PVRR impacts, the Companies have not provided granular results of their reanalysis of portfolios from Table 8 of the Retirement Assessment under different coal-to-gas ratio scenarios.[356] Instead, the Companies provide an average PVRR benefit under the mid coal-to-gas ratio scenarios, presumably across all the Table 8 portfolios, which is an insufficient basis for insight into which alternative portfolios performed better or worse. The Companies continue to provide an average of net-PVRR benefits across the remaining five coal-to-gas ratio cases. That average is even less helpful, and less granular, affording no insight into relative portfolio risk under different fuel price assumptions. The most helpful PVRR detail provided is arguably the high and low net-PVRR results from the remaining five coal-to-gas ratio cases, but the incredible range between those high and low examples raises more questions than answers, including: which price case is behind each of the high and low examples; which portfolio was behind each of the high and low

[356] LGE/KU Resp. to JI PH Q1(a). The Companies do appear to have incorporated the updated cost numbers for the NGCCs from the EPC RFP bid results into the alternative portfolios modeled in response to Staff's post-hearing data requests, but do not appear to have rerun the modeling that was presented in the Resource Assessment with the updated NGCC numbers.

examples; what was the median net-PVRR change; what was the standard deviation of net-PVRR changes; and more.

Knowing so little about the analysis undertaken, and having no opportunity to look behind the Companies' narrative claims, Joint Intervenors are unable to draw any meaningful conclusions about the exact magnitude of benefits lost as a result of the increased capital cost estimates. Joint Intervenors acknowledge that the Companies' judgment is not constrained by the same informational asymmetry, but the Companies certainly have not had the opportunity to revisit, from Stage One, Step One of their 2022 Resource Assessment, whether it would lead to different portfolio options and a different preferred portfolio.

Yet, the Companies are as convinced as ever that Mill Creek Unit 5 and Brown Unit 3 are still a good bet for customers.[357] In fact, the Companies seem to view the significantly increased capital costs as a reason to move forward with both NGCCs as quickly as possible, offering no commitment of further analysis or optimization modeling. In Mr. Bellar's narrative response, to explain the reasons to rush forward, Mr. Bellar explains that [BEGIN CONFIDENTIAL] [redacted]"[358][END CONFIDENTIAL] But that claim is inconsistent with Confidential Attachment 1 to the same response, which speaks for itself: [BEGIN CONFIDENTIAL] [redacted]."[END CONFIDENTIAL][359] Mr. Bellar's representations about suppliers' motivations are hearsay, and concerningly conflict with the suppliers' own written

---

[357] LGE/KU Resp. to JI PH Q1(a).
[358] *Id.*
[359] Confidential Attach. 1 to Resp. to JI-PH Q.1(a).

communications. In light of that conflict, Mr. Bellar's hearsay statement should be given no weight.

E. Significant threat of future GHG-related compliance costs that have not been incorporated into analysis and Companies have not attempted to quantify.

In addition to the other ways in which the Companies' under-estimated NGCC costs, as discussed above, the Companies cannot credibly claim that they have successfully presented a least-cost portfolio when in fact, they do not know, and are unable to accurately estimate, the costs of future regulatory compliance with greenhouse gas requirements.

On May 11, 2023, the EPA released its proposed rule, "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (hereinafter "Proposed New GHG Rules"). These proposed rules, although not yet final, are anticipated to be finalized in some form in 2024 and are evidence of both the uncertainty and likelihood of future greenhouse gas regulatory requirements.

As the Commission has previously acknowledged, because the greenhouse gas regulatory environment is highly uncertain, it is reasonable and prudent to take potential CO_2 compliance costs into consideration.[360] Due to this uncertainty that future compliance introduces into Companies' proposed portfolio, the record does not provide a sufficient basis for the Commission to conclude that the Companies have reasonably accounted for future greenhouse gas related compliance costs for several reasons.

[360] Case No. 2014-00002, *Joint Application of LG&E-KU for CPCN for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station*, Final Order at 11 (Ky. PSC Dec. 19, 2014).

Initially, when asked about potential compliance pathways, such as carbon capture and sequestration or hydrogen co-firing, the Companies argued it would be premature to make any decisions regarding compliance given the other large changes the Companies' generation portfolio that would result from the proposed regulation of existing coal units. [361] In the other words, the Companies do not currently know how the two proposed NGCCs would comply with the New GHG Rules if they are finalized as proposed and agree that there are "significant uncertainties" with compliance that still need to be resolved.[362]

When asked about necessary infrastructure upgrades and modifications that would be necessary to accommodate hydrogen should it be needed, the Companies stated that at minimum, to accommodate hydrogen they anticipated the need for "new or upgraded combustors, upgraded gas supply piping size and material of construction, larger gas turbine enclosures, fuel blending skids, larger Heat Recovery Steam Generator ("HRSG") to accommodate additional Selective Catalytic Reduction ("SCR") equipment, as well as significant upgrades to the existing natural gas pipelines to support the supply and transport of hydrogen to the extent it is required."[363] While recognizing the magnitude of these potential infrastructure challenges, the Companies still did not attempt to estimate the costs of these upgrades and modifications.[364] Nor do the Companies know where the low-GHG hydrogen would come from that they would need to co-fire the NGCCs to comply with the New GHG Rules or how much it would cost.[365]

With respect to carbon capture and sequestration as a compliance option for the proposed NGCC units, the Companies do not even believe that technology is feasible to implement in its

---

[361] LGE/KU Resp. to Supplemental JI Q 107(b).
[362] Aug. 25, 2023 HVT at 16:27:50–16:29:14.
[363] LGE/KU Resp. to Third JI Q 17(b).
[364] LGE/KU Resp. to Fourth JI Q 16.
[365] Aug. 25, 2023 HVT at 16:29:14–16:30:21.

current state and therefore do not believe it is likely to be a feasible compliance pathway for the New GHG Rules.[366]

The Companies ultimately assert that the EPA's Proposed New GHG Rules do not require carbon capture or hydrogen co-firing per se.[367] The Companies believe that by limiting a unit's annual capacity factor, it is possible to comply with the proposed GHG standards without an increase in capital cost for the proposed units.[368] However, the Companies did not perform any analysis to understand the economic impact of the Proposed New GHG Rules on the proposed NGCC plants, opting instead to wait to conduct the appropriate analyses until after the rules become final.[369] In the meantime, the Companies relied on EPA's modeling of the proposed standards, which demonstrated that new NGCC capacity could continue to operate without CCS or hydrogen co-firing by limiting their capacity factor to below 50%, to argue that the proposed greenhouse gas new source performance standards would not make the NGCCs uneconomical.[370]

As explained by Joint Intervenors' Witness Anna Sommer, in response to Commission Staff request 5-2, the Companies state that they do not have necessary information needed to perform an accurate analysis of the effect of compliance with the proposed new GHG rules and they cannot model hypothetical investments.[371] Nevertheless, the Companies did conduct a late-in-the-game "stress test" of their previous modeling results by introducing new assumptions based on the proposed New GHG Rules in an attempt to address the potential impact of the New

[366] Aug. 25, 2023 HVT at 16:31:44–16:33:03.
[367] LGE/KU Resp. to Third JI Q 20.
[368] LGE/KU Resp. to Third JI Q 18(c).
[369] LGE/KU Resp. to Third JI Q 16(c).
[370] LGE/KU Resp. to Third JI Q 16(b).
[371] Sommer Direct at 50.

GHG Rules.[372] Operating on the assumption that EPA would implement the New GHG Rules as proposed, the Companies sought to evaluate the effect that the only compliance alternative that could be modeled currently to a reasonable degree of accuracy (i.e., an operating constraint of a 50% annual capacity factor on the Mill Creek and Brown NGCCs) would have on the Companies' least-cost compliance plan for the Good Neighbor Plan and the retirement of Brown 3. Ultimately, the Companies determined that the results still favored the proposed NGCC units and solar PPAs across a majority of modeled scenarios.

As Ms. Sommer explains, while this was a good faith attempt to model the EPA rule requirements on an extremely short timeframe, it falls short with respect to evaluating non-fossil replacement for the retiring coal units.[373] Accordingly, Companies have failed to properly quantify the known costs of compliance with future GHG regulations, with additional unknown costs posing a significant threat to the proposed NGCCs. This is another ground upon which the Companies have failed to establish that the proposed NGCCs reflect the least-cost option, and therefore this application must be denied.

VII. BATTERY ENERGY STORAGE SYSTEMS

The Companies' evidence in support of the Brown BESS may reflect wasteful duplication, with uncompetitive project-specific costs and increased carbon emission risk.[374] Joint Intervenors can no longer recommend approval of the requested Brown BESS CPCN. In two parts, Joint Intervenors will (A) summarize evidence related to these indicia of wasteful duplication and call for the Companies to re-issue an RFP for utility-scale storage, and (B) argue

[372] LGE/KU Resp. to Fifth Staff Q 2.
[373] Sommer Direct at 50–51.
[374] *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 173 (Ky. 1965) (requirement to avoid wasteful duplication "embraces an excess of capacity over need, and excessive investment in relation to productivity or efficiency, or an unnecessary multiplicity of physical properties.").

that the Companies should pursue programmatic support for customer-sited energy resources—especially storage—which offer multiple benefits for the Companies and customers, including improved reliability, greater resilience, and lower costs.

A. While Joint Intervenors support the development of utility-scale storage, the proposed Brown BESS reflects wasteful duplication.

As observed by others, the utility-scale storage projects offered in response to the RFP and offered to the model in the Stage One resource optimization modeling were not selected as least-cost resources.[375] Given all the limitations and shortcomings in that modeling,[376] however, that fact alone is hardly convincing of the potential value of storage as part of a least-cost, reliable system.[377]

But even if one assumes the modeling packaged into the Resource Assessment (Ex. SAW-1) is credible, it cannot support selection of the Brown BESS. The Brown BESS was not selected by the model; it was cherry-picked from the RFP results and added to the proposed portfolio at "Stage Three, Step Two" of the Resource Assessment. This was a cherrypicked step in the process in which the Companies only performed production cost modeling of portfolios that added the Brown BESS.[378] At no point did the Companies competitively model the Brown BESS against alternative storage projects.

---

[375] *E.g.*, KIUC Witness Kollen at 6–7; KCA Witness Medine at 11; LG&E/KU Resp. to Staff Post-Hearing Request Q 20.
[376] *See generally* Sommer Direct at 3–11, 25–51.
[377] *See infra* subsection B.
[378] Attach. 2, Ex. SAW-1 at 36 (of 104), LGE/KU's Resp. to JI Q 2-60(a), 2022 Resource Assessment (May 2023 Update). Throughout this brief, references to Ex. SAW-1 are intended to refer to the Companies' May 2023 Update version unless stated otherwise.
("The SCCT and battery options the Companies evaluated were the SCCT and Brown BESS proposals provided as RFP responses by the Companies' Project Engineering group with input from HDR[.]").

Among the storage projects bid in response to the Companies' RFP, the proposed Brown BESS was not the most cost-effective option.[379] And this was true even despite the fact that the RFP did not allow outside bidders to seek use of LG&E-KU's existing plant sites and transmission access—a competitive advantage that was reserved exclusively to the Companies.[380] Even with that inherent advantage, the proposed Brown BESS is not the least-cost battery storage option.

The Companies' justification for proposing an uncompetitively priced self-build battery storage resource is only a claim that "battery ownership will allow the Companies to gain valuable operational experience with such systems at utility scale, which will likely be an integral part of integrating increasing amounts of renewable generation in future."[381] But ownership of the resource is not necessary for the Companies to have operational responsibilities and gain experience with the technology. In lieu of owning the BESS outright, the Companies could include a structured role for their employees in the management and operations of a BESS facility that could be supplied and owned by a third-party at a lower cost to the Companies and ratepayers.

Additionally, the Companies' evidence suggests that addition of the Brown BESS to their portfolio would *increase* emissions from fossil generating units.[382] That suggests a mismatch

---

[379] *Id.*

[380] Ex. CRS-1, Request for Proposals at 3 (June 22, 2022) ("Third party respondents should not assume access to, or utilization of, existing sites owned by the Companies for siting proposed project(s)."); *see also, e.g.*, Aug. 24, 2023 HVT at 16:47:00 to 16:50:05 (witness explains some advantages of using existing plant sites); LGE/KU Resp. to JI 1.160(d) (acknowledging that "co-location of operations and maintenance resources and access to existing transmission infrastructure are advantages").

[381] Ex. SAW-1 at 36.

[382] *See* Sinclair Rebuttal, Ex. DSS-2 at 7 ("Based on the Companies' expected generating portfolio, the Brown BESS is most likely to be charged overnight when load is lowest (and incremental generation is cheapest), and the likeliest source of generation to charge it will be coal, as SCCTs are generally offline and NGCCs are expected to run near maximum capacity.").

between the Companies' emission risk exposure and environmental liabilities associated with those units and the urgent to need to mitigate that risk by transition to non-emitting resources. On balance, Joint Intervenors cannot avoid the conclusion that the proposed Brown BESS would be an excessive and imprudent investment, bringing potential for increasing operational costs and emissions risks.

However, Joint Intervenors continue to support utility-scale storage as an essential resource in the Companies' changing resource portfolio, as renewables and distributed resources grow to play a more prominent role. We recommend that the Companies issue a new RFP to seek updated storage proposals, providing bidders the option to utilize the Companies' facilities at the Brown Station. This will have the twin benefits of further reducing costs for ratepayers, while providing the Company with on-site access to the BESS at their own facility. The new RFP should include provisions that enable the Companies to actively participate in the management and operations of the BESS facility.

If the Companies' view BESS ownership as key to gain valuable operation experience, it should be embarked on in conjunction with addressing a need, or a problem to solve in the present and sized to address that problem. For example, if a proposed PV facility variable output needs to be stabilized in order to connect to the grid, propose battery sized for that need. If there is a locational troubling spot on the grid, consider BESS to provide ancillary service to stabilize. If the value of a renewable energy project can increase by adding storage to deliver firm energy commitments during certain hours of the day (i.e. dispatchable solar) that is the time to explore BESS ownership.

B. The Companies Should Leverage Distributed Resources as an Asset to Reduce Costs and Create Multiple Benefits, including Improvements to Reliability, Resilience, and Affordability.

We share the Companies' view that battery storage systems will have an integral role in the electricity grid as the energy transition progresses. That role will include distributed storage systems as well as utility-scale storage. We recognize the value of the Companies gaining real-world, operational experience with utility-scale storage systems, and just as important, if not more-so, is experience with distributed energy resources, including storage. There is no time to waste, as the hearings in this case have demonstrated—the Companies' need for new, cleaner, and reliable resources has been well-established, and the timeline for bringing them online is short. Distributed energy resources are an enormous asset the Companies can leverage to improve reliability, increase resilience, enhance the distribution grid, and reduce costs for customers.

As Andrew McDonald demonstrated in his testimony, customer-sited battery storage systems can be deployed rapidly and scale up to the tens and hundreds of MW in a relatively short period. These storage systems can be installed in small or large units, depending on the needs and interconnection capacity of the customer (10 KW at a residence, hundreds or thousands of KW at commercial locations such as schools, hospitals, businesses, and industrial facilities). Customers want these batteries for reliability and security, to protect them against grid outages. They combine well with solar, providing additional resilience and bill savings. They can provide the benefit of reduced peak demand charges and opportunity to change load profile enough to financially warrant opting into Time-of-Day tariffs.

The Companies should seize this opportunity and make the most of it. Unlike utility-scale storage, where the Companies must make the investment in the equipment and pay for ongoing operations and maintenance, customer-sited storage is purchased by the end-user. The customer makes the investment and pays to maintain the equipment. Yet this customer-owned resource has enormous value for the utility, especially if they can be involved, cooperatively with the customer, to manage charges and discharges, as utilities such as Green Mountain Power do. For instance, cooperatively managed could mean utility control of just 50 percent of the storage resource, leaving the other 50 percent always available to the customer for backup power. Or, cooperatively managed could mean sending a price signal (via text alert or phone app.) to customer to allow battery to be discharged remotely with compensation credited on next bill.

What would be the optimal program design to cost-effectively incentivize the rapid deployment of customer-sited batteries? How much would the Companies need to pay customers to gain the right to control battery charging and discharging? How much of an incentive would be needed to double or quadruple customer adoption of batteries? Or to achieve 500 MW of customer-sited battery storage by 2028? How would these costs compare to the cost of utility scale storage and other supply- and demand-side resources? What additional benefits could the Companies leverage from these distributed battery systems, such as enhancements to the distribution grid? These questions should be studied and answered without delay.

VIII. CONCLUSION

For the reasons laid out above, Joint Intervenors respectfully request that the Commission approve the proposed DSM/EE Plan, with the modifications and additional conditions set forth above; conditionally approve the proposed fossil fuel generating unit retirements, subject to the Companies re-submitting adequately supported CPCN requests; deny without prejudice the requested CPCNs for the two proposed NGCCs and the BESS; and approve the Companies' requests for approval of the Mercer County and Marion County Solar Projects and the solar PPAs.

Respectfully submitted,

____

Tom FitzGerald
Ashley Wilmes
Byron Gary
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602
(502) 551-3675
FitzKRC@aol.com
Ashley@kyrc.org
Byron@kyrc.org

Thomas Cmar (appearing *pro hac vice*)
Cassandra McCrae (appearing *pro hac vice*)
Gilbert Zelaya (appearing *pro hac vice*)
Earthjustice
6608 Wooster Pike
Cincinnati, OH 45227
(312) 257-9338
tcmar@earthjustice.org
cmccrae@earthjustice.org
gzelaya@earthjustice.org

Counsel for Joint Intervenors

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 September 22, 2023; that the documents in this electronic filing are a true representations 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.

Tom FitzGerald