COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

REBUTTAL TESTIMONY OF
STUART A. WILSON
DIRECTOR, POWER SUPPLY
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: July 18, 2025

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INTRODUCTION

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

A. My name is Stuart A. Wilson. I am the Director of Power Supply for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 2701 Eastpoint Parkway, Louisville, Kentucky 40223.

Q. What is the purpose of your rebuttal testimony?

A. First, I rebut the testimony of Kentucky Coal Association ("KCA") witness Emily Medine and demonstrate that the Companies' coal-to-gas ("CTG") methodology for forecasting coal prices remains reasonable.

Second, contrary to the assertions of Attorney General and Kentucky Industrial Utility Customers, Inc. ("AG-KIUC") witness Leah Wellborn, I show the Companies modeled a wide range of potential economic development load growth and showed that the Companies' proposed resources are least-cost across a broad range of potential future scenarios.

Third, I rebut Joint Intervenors witness John W. Chiles's assertion the Companies have not adequately or appropriately accounted for "transmission import capacity" on loss of load expectation ("LOLE") calculations and have thereby overstated the need for new generation resources.

Fourth, I show the Companies have fully addressed the economics of battery energy storage systems ("BESS") in this proceeding and demonstrated that if existing investment tax credits ("ITCs") remain in place and trade tariffs do not substantially affect pricing, the Cane Run BESS will be a valuable resource to serve existing load while rapidly adding new high load factor customer loads.

Fifth and finally, I argue the Commission should reject Joint Intervenors witness Sean O'Leary's assertions concerning the economics of natural gas combined cycle ("NGCC") units versus demand-side management and energy efficiency ("DSM-EE") programs.

Q. Do you have any overarching observations concerning intervenor testimony as it concerns the Companies' resource modeling and assessment efforts?

A. Yes. Importantly, none of the intervenor witnesses attempted to conduct resource modeling to dispute the Companies' rigorous modeling efforts and conclusions. In contrast, the Companies have conducted extensive modeling for this proceeding and the following outcomes are clear:

- New resources are needed to support economic development load growth.
- The need for the Brown 12 and Mill Creek 6 NGCCs is abundantly clear. Brown 12 and Mill Creek 6 are included in the least-cost portfolio for all scenarios evaluated in the 2025 CPCN Resource Assessment (Exhibit SAW-1) and all scenarios used to evaluate a Mill Creek 2 life extension (see PSC 3-8(b), Attachment 1, "Modeling Mill Creek 2 Life Extension as a Resource Planning Alternative"). NGCC is by far the most economic new source of round-the-clock energy and capacity.
- With a 40% investment tax credit and minimal trade tariff impacts, Cane Run BESS is the least-cost new source of peaking capacity. Cane Run BESS will

leverage the energy-producing capabilities of the Companies' new and existing baseload resources to support reliability during hot and cold weather events.

Rather than attempt to perform resource modeling of their own, the intervenor testimony in this proceeding that addresses the Companies' modeling consists of primarily qualitative criticisms of particular modeling inputs. Notably, the intervenors do not question or criticize the modeling itself. Other witnesses for the Companies address criticisms related to the economic development load forecast; I address the other criticisms below.

KENTUCKY COAL ASSOCIATION WITNESS EMILY MEDINE'S CRITICISMS OF THE COMPANIES' COAL-TO-GAS METHODOLOGY ARE UNFOUNDED

Q. Kentucky Coal Association ("KCA") witness Emily Medine devotes a substantial portion of her testimony to attacking the Companies' coal-to-gas ("CTG") ratio-based fuel price forecast methodology, which was an important input to the Companies' resource modeling efforts.[1] Is the Companies' CTG approach reasonable?

A. Yes. I have reviewed Ms. Medine's testimony from the Companies' 2022 CPCN proceeding (Case No. 2022-00402), and there is nothing fundamentally new or different about Ms. Medine's criticisms of the Companies' CTG methodology in this proceeding compared to her testimony in that proceeding.[2] As in that case, Ms. Medine

[1] Medine at 13-23.
[2] Consider the Commission's summary of the relevant portion of Ms. Medine's testimony in its final order in that proceeding:

> The Commission further notes that Kentucky Coal Association criticized the manner in which LG&E/KU projected coal prices. Specifically, Kentucky Coal Association indicated that LG&E/KU should have projected coal prices directly as opposed to projecting coal prices based on a relationship between coal and natural gas prices. Kentucky Coal Association's witness, Emily Medine, indicated that the coal price forecasts should have considered the supply curves

has in this case neither provided a recommended coal price forecast nor performed any resource modeling of her own with whatever her preferred fuel price forecasts might be; thus, she offers no insight into what the effects of using her preferred but unidentified fuel price forecasts would be. Notably, the Commission's final order in Case No. 2022-00402 explicitly considered and rejected Ms. Medine's criticisms while accepting the Companies' CTG approach as reasonable.[3]

> The Commission finds that LG&E/KU's evidence regarding the relationship between coal and natural gas prices is credible. … LG&E/KU provided evidence showing a correlation between a reduction in the number of coal mines and its increased reliance on two suppliers who are now providing 79 percent of LG&E/KU's coal, which supports its assertion of reduced coal on coal competition that, if anything, could tie coal prices more closely to gas prices. Thus, whether projected separately or together, the Commission believes that it is reasonable to assume a relationship between coal prices and natural gas prices.
>
> … LG&E/KU also considered a spread of fuel price scenarios and ratios both above and below the historical correlation between coal prices and fuel prices, which permitted stress testing of projected prices. Finally, it is not necessary to capture volatility in long-term forecasts, because it should balance out over time. Thus, the Commission finds that LG&E/KU's fuel price scenarios were reasonable and that they did not affect the reasonableness for LG&E/KU's production cost and financial modeling.[4]

> for each coal type, demand for coal in domestic and export markets, and the price of alternative energy sources. Ms. Medine acknowledged that there is a relationship between coal and natural gas markets but stated that the methodology used by LG&E/KU is not based on an established methodology for forecasting coal prices. Ms. Medine alleged that LG&E/KU used the coal to gas price methodology to support its desired result and as proof noted that LG&E/KU's coal price projections from their 2021 IRP, which Ms. Medine indicated were projected directly, were significantly lower than coal price projections in this case. Ms. Medine also stated that due to the longer-term nature of coal contracts, utilities are able to hedge against price changes in a way that is not possible with natural gas contracts.

Case No. 2022-00402, Order at 91-92 (Ky. PSC Nov. 6, 2023).

[3] *Id. at* 91-94.

[4] *Id. at* 93-94.

Tellingly, Ms. Medine provides no reason for the Commission to change its analysis of and conclusion regarding her exact same points made less than two years after the Commission rejected them. Indeed, the evidence the Commission cited as being particularly compelling concerning tying coal prices more closely to gas prices, namely the number of mines supplying the Companies and the concentration of that supply, remains just as compelling, if not more so, with fewer suppliers and mines and still a high concentration of supply in the two largest suppliers:

Companies' Coal Supply					
	2010	**2015**	**2020**	**2022**	**2024**
Suppliers	27	21	13	13	8
Mines	36	31	26	22	18
Two largest suppliers (%)	45%	65%	55%	79%	73%

It is also important to note the Companies' response to KCA 1-8(c), in which the Companies stated, "Notably, in 2025 the coal-to-gas ratio based on market coal and gas prices is 0.56 …. This indicates a reversion from the much higher market coal-to-gas price ratios experienced in recent years to a price ratio that is more reflective of the long-term average, which the Companies used as the 2025 CPCN Mid coal-to-gas price ratio." The Companies' CTG ratios also find support in the average ratio of new NGCC (such as Brown 12 and Mill Creek 6) and coal operating efficiencies, i.e., the ratio of their heat rates:[5]

Coal Unit	**Average Heat Rate (2016-2021)**	**Ratio of New NGCC (6,200 Btu/MWh) and Coal Heat Rates**
Brown 3	11,796	0.53
Ghent 2	10,633	0.58
Mill Creek 3	10,694	0.58
Mill Creek 4	10,472	0.59
	Average	0.57

[5] Companies' Response to JI 1-112.

In addition, as Mr. Schram notes in his rebuttal testimony, Ms. Medine states in her own testimony that at least at one time coal price increases were caused in part by increased natural gas prices.[6] Ms. Medine is not the only one to observe that coal and gas prices are related; for example, the U.S. Energy Information Agency's Short-Term Energy Outlook Coal Module includes Henry Hub natural gas prices as an independent variable in its regression models to forecast coal prices.[7]

In short, nothing in the record of this proceeding suggests there is less evidence to support the reasonableness of the Companies' CTG methodology than there was in the 2022 CPCN case in which the Commission expressly accepted the methodology over Ms. Medine's criticisms; indeed, there is more evidence that prices are reverting to the long-term CTG ratio that underlies the Companies' mid-CTG fuel price scenarios. Therefore, the Commission should follow its own reasoning of less than two years ago and the evidence in the record of this proceeding in rejecting Ms. Medine's CTG criticisms in this case.

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[6] Medine at 20, lines 1-6 ("Prompt year coal prices from these regions going into COVID had been relatively flat. There was an initial bump in pricing during early COVID which was not sustained and then a significant increase in pricing from mid-2022 through the first half of 2023. *The reasons for the significant bump were increased demand due to COVID recovery, a delayed response from the coal industry in restarting idled production,* ***and higher gas prices*** due to strong global pricing resulting in part from the war in Ukraine" (emphases added).).

[7] U.S. EIA, "Handbook of Energy Modeling Methods: Short-Term Energy Outlook Coal Module" at 3 and 16-17 (updated 2022), available at https://www.eia.gov/analysis/handbook/pdf/STEO_Coal_Model.pdf (accessed June 28, 2025). Note especially *id.* at 17:

> *Regional electric power sector coal prices*
> The STEO Electricity Supply Model requires forecasts of delivered regional coal prices for the electric power sector that correspond to the four coal demand regions. …
>
> We use regression models to estimate the prices for each of the four main regions (in cents per million British thermal units) as functions of these independent variables:
> - Composite spot coal price
> - Henry Hub natural gas spot price
> - Retail diesel fuel price (on-highway)
> - Regional power sector coal stocks (inventories)
> - Monthly seasonal dummy variables

CONTRARY TO AG-KIUC WITNESS LEAH WELLBORN'S ASSERTIONS, THE COMPANIES MODELED A BROAD RANGE OF POSSIBLE FUTURE LOAD SCENARIOS AND DEMONSTRATED WHY THE COMMISSION SHOULD APPROVE THE REQUESTED CPCNS TO MEET CUSTOMERS' FUTURE NEEDS ACROSS A BROAD RANGE OF POSSIBLE FUTURES

Q. AG-KIUC witness Leah Wellborn asserts the Companies' modeled range of potential economic development load growth is too narrow.[8] Was the Companies' range of modeled economic development load growth reasonable?

A. Yes, it was reasonable. The Companies' 2025 CPCN Resource Assessment modeled a 560 MW range of possible data center load in 140 MW increments centered on the Companies' load forecast of 1,750 MW of data center load by 2030 (i.e., from 1,470 MW to 2,030 MW).[9] The Companies also modeled 1,002 MW of data center load in response to PSC 2-1, as well as 1,050 MW and zero MW of data center load in the Companies' 2024 IRP proceeding.[10] Therefore, the record of this proceeding includes the Companies' modeling of a broad swath of load growth scenarios, ranging from 0 MW of economic development load to more than 2,000 MW of economic development load growth by 2030. Thus, contrary to Ms. Wellborn's assertions, the range of load growth the Companies modeled cannot reasonably be called "narrow."

Q. What does the Companies' resource modeling show across this broad range of modeled load scenarios?

A. The Companies' modeling consistently shows that adding Brown 12 and Mill Creek 6 are part of least-cost portfolios across a wide range of possible future scenarios. For example, the Companies' analysis in response to PSC 3-8(b) shows that across all ITC

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[8] Wellborn at 7-8.
[9] Wilson Direct, Exh. SAW-1 at 30-31. *See also* Companies' Response to PSC 3-8(b), Attachment 1, "Modeling Mill Creek 2 Life Extension as a Resource Planning Alternative."
[10] Case No. 2024-00326, IRP Vol. III, 2024 IRP Resource Assessment.

and trade tariff scenarios studied and adding data center load between 1,470 MW and 2,030 MW, adding Brown 12, Mill Creek 6, and the Ghent 2 SCR was part of the least-cost portfolio across the five fuel price scenarios (with a 40% ITC and no trade tariff impacts, some additional BESS is also least-cost). The Companies also showed that adding both Brown 12 and Mill Creek 6 would be needed to reliably serve more than 1,000 MW of new economic development load with no ITC for BESS.[11] The Companies have further demonstrated that adding large amounts of NGCC capacity would be least cost even if there were no load growth in a scenario where the current Clean Air Act 111(b) and (d) greenhouse gas rules remain in effect.[12]

In short, the Companies have demonstrated that the resources they have proposed in this proceeding would be part of a least-cost portfolio across a broad range of possible futures—especially Brown 12 and Mill Creek 6. Based on the analysis my team and I have performed, I recommend the Commission approve all requested CPCNs so the Companies can have the tools they need to meet the challenges and opportunities of the future as they arise.

JOINT INTERVENORS WITNESS JOHN CHILES IS INCORRECT IN ASSERTING THE COMPANIES DID NOT ADEQUATELY ACCOUNT FOR TRANSMISSION IMPORT CAPACITY

Q. Joint Intervenors witness John W. Chiles asserts the Companies have not adequately or appropriately accounted for "transmission import capacity" on loss of load expectation ("LOLE") calculations and have thereby overstated the need for new generation resources.[13] Is Mr. Chiles mistaken?

[11] Companies' Supplemental Response to KCA 1-4, Attachment 1 at 10, Table 2.
[12] Case No. 2024-00326, IRP Vol. III, 2024 IRP Resource Assessment at 48, Table 28.
[13] Chiles at 8-12.

A. Yes. The Companies explicitly account for different levels of available transfer capacity ("ATC") in their resource adequacy modeling and LOLE calculations. As explained in the Companies' 2024 IRP Resource Adequacy Analysis, the Companies model ATC in SERVM based on the distribution shown in Table 18 below, which summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer and winter months of 2022, 2023, and 2024.

Table 18: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	221	55%
1 – 199	24	6%
200 - 399	20	5%
400 - 599	27	7%
600 - 799	16	4%
800 - 999	13	3%
>= 1,000	84	21%
Total	405	

Thus, in calculating LOLE, the daily ATC in SERVM ranged from 0 MW to 1,000 MW or more in accordance with the probability distribution shown above, and the heading in Mr. Chiles's testimony that asserts the Companies have not "factored in the impact of transmission import capacity on the calculation of loss of load expectation" is incorrect.

But it is also important to bear in mind that having abundant ATC is not a panacea for meeting customers' needs if there is no generation available on the other side. Mr. Chiles implicitly concedes this concerning the Companies' experience during Winter Storm Elliott:

> Adding transmission capacity to external systems can create pathways for generators located in adjacent energy markets which can now be available in emergency conditions to improve the ability of the area to serve load. This was seen during Winter Storm Elliott when the

> Companies claimed they had plenty of transmission capacity to import from PJM. Under extreme weather conditions, capacity from other markets may not be available, but if insufficient transmission capacity exists, then it does not matter how much external capacity is available.[14]

To be clear, lack of ATC did not result in the first-of-its-kind load shedding event for the Companies Winter Storm Elliott; rather, when the Companies and their customers needed energy the most, *there was no energy to buy*.[15] For example, the Companies had been purchasing 400 MW of power from PJM, but PJM cut the export to avoid its own load curtailments.[16] What Winter Storm Elliott highlighted was not the need for more ATC during extreme weather events, but rather the need for more generating resources—the opposite of what Mr. Chiles asserts.

Q. Mr. Chiles goes on to assert that "by not including the effect of expansion of transmission ties on the LOLE calculation, … the Companies have potentially overstated their need for new generation."[17] Is he correct?

A. No. Mr. Chiles fundamentally misunderstands the purpose and conclusions of the Companies' ATC sensitivity analysis in their 2024 IRP Resource Adequacy Analysis.[18] Having ample ATC serves no purpose if there is no generating resource on the other end to serve customers, and having the rights to transmit energy across the relevant transmission facilities to the Companies' customers is not free. Thus, what the Companies' ATC sensitivity analysis showed is (1) there is relatively little impact to having zero ATC (annual LOLE increases from 1.00 to 1.10) compared to the base case, and (2) having a minimum of 700 MW of ATC at all times can significantly

[14] Chiles at 10-11.
[15] *Electronic Investigation of Louisville Gas and Electric Company and Kentucky Utilities Company Service Related to Winter Storm Elliott*, Case No. 2023-00422, Order at 5-7 (Ky. PSC Jan. 7, 2025).
[16] *Id.* at 7.
[17] Chiles at 11, lines 14-16.
[18] Chiles at 11-12.

improve LOLE (from 1.00 to 0.15) if the system on the other side is assumed to have a 1-in-10 LOLE of its own (i.e., will nearly always be able to provide 700 MW of power to the Companies).[19] The Companies' choice of 700 MW was not arbitrary; 700 MW is the sum of ATC to the Companies from MISO (300 MW), PJM (300 MW), and TVA (100 MW) for which no transmission system upgrades would be required. The cost of obtaining firm transmission service to ensure the Companies could receive power from the neighboring system would be about $101 million per year.[20]

Mr. Chiles's criticism appears to be that purchasing 700 MW of firm transmission in all hours would be excessive and unnecessary given the impact of that amount of a reliable import on LOLE; because 700 MW of around-the-clock firm transmission had such a profound LOLE impact, presumably a smaller amount for fewer hours could still have an appreciable impact and perhaps reduce the Companies' owned or contracted generation needs. But Mr. Chiles overlooks several crucial points:

- First, the Commission clearly stated in the Companies' 2022 CPCN case, "'This Commission has no interest in allowing our regulated, vertically integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time.' … [T]his Commission expects LG&E/KU to own or contract for the necessary resources, not depend on a capacity market where someone else is in charge of weatherization, maintenance and fuel assurance of those resources."[21] Thus, just having access to neighboring systems and hoping

[19] Case No. 2024-00326, IRP Vol. III, 2024 IRP Resource Adequacy Analysis at 16-17 (Oct. 18, 2024).
[20] *Id.* at 17.
[21] Case No. 2022-00402, Order at 177 (Ky. PSC Nov. 6, 2023).

they will have energy when needed is not consistent with the Commission's clear directive.

- Second, consistent with reliable system planning and the Commission's directive quoted above, if an owned or contracted resource will reside outside the Companies' transmission system, they will need to secure firm transmission service to ensure they can obtain power from the resource when needed.
- Third, firm transmission service adds cost to a resource. Thus, unless there is a low-cost resource waiting to be purchased or contracted in a neighboring system, the only effect of siting a new resource outside the Companies' transmission system is to add cost, making it uneconomical. The Companies have not received offers for any such resources and are not otherwise aware of them.
- Fourth, the Companies' neighboring systems have well known capacity and reliability challenges of their own. According to NERC's 2024 Long-Term Reliability Assessment, MISO is a high-risk area for 2025-2029, and PJM in an elevated risk area for 2026-2029,[22] though NERC recently stated it would revise its assessment of MISO to being elevated risk for 2025-2027 and high risk for 2028-2031.[23] Thus, Companies' neighboring markets are looking for new

[22] North American Electric Reliability Corporation ("NERC"), "2024 Long-Term Reliability Assessment" at 6 (Dec. 2024) ("Areas categorized as High Risk fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. Elevated-Risk areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves."), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed June 29, 2025).

[23] NERC, "Statement on NERC's 2024 Long-Term Reliability Assessment" (June 17, 2025), available at https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx (accessed June 29, 2025).

- capacity; they are not awash in excess capacity and energy to sell the Companies if only sufficient transmission were available.
- Fifth and finally, as I discussed above, the lesson of Winter Storm Elliott reinforces all of these points: In extreme weather events, the Companies cannot count on neighboring systems to have energy to sell, even when there is ample ATC for such transfers.

For all of these reasons, there is no merit to Mr. Chiles's assertion that the Companies have overstated the need for generation by inadequately considering transmission options.

IF TAX CREDITS AND TRADE TARIFFS RESULT IN FAVORABLE ECONOMICS, CANE RUN BESS WILL BE VITAL TO SERVING EXISTING CUSTOMERS AND MORE FULLY USING EXISTING RESOURCES WHILE ACCOMMODATING NEW LOAD

Q. Some intervenor witnesses have expressed concerns about the economics of the Companies' proposed Cane Run BESS.[24] How do you respond?

A. The Companies have fully addressed the economics of BESS in this proceeding and demonstrated that if existing investment tax credits ("ITCs") remain in place, as it now appears they will for Cane Run BESS,[25] and trade tariffs do not substantially affect pricing, the Cane Run BESS will be a valuable resource to serve existing load while rapidly adding new high load factor customer loads. The Companies' resource assessments in this proceeding show that with a 40% ITC and pricing consistent with the Companies' cost estimate of approximately $775 million, the full 400 MW of four-

[24] *See, e.g.,* Kollen at 16-18; Wellborn at 19-25.

[25] *See* U.S. 2025 H.R. 1, "One Big Beautiful Bill Act," available at https://www.congress.gov/bill/119th-congress/house-bill/1/text; NPR, "Trump on Fourth of July signs 'One Big Beautiful Bill' to implement his agenda" (July 4, 2025), available at https://www.npr.org/2025/07/03/nx-s1-5454841/house-republicans-trump-tax-bill-medicaid (accessed July 5, 2025).

hour Cane Run BESS is a least-cost resource to serve the loads anticipated in the 2025 CPCN Load Forecast (i.e., including 1,750 MW of new high load factor customer loads).[26] This is true across all of the environmental scenarios evaluated in the 2024 IRP Resource Assessment with a 50% ITC, as well.[27]

But the Companies have openly acknowledged that the economics of Cane Run BESS depend on an adequate level of ITC and minimal trade tariff impacts. The Companies' recent analysis in response to PSC 3-8(b) shows that if there is either an inability to qualify for an ITC, which now appears unlikely, or a 30% BESS cost increase (due to trade tariffs or otherwise), Cane Run BESS would not be least-cost in any of the load scenarios studied (i.e., new high load factor loads ranging from 1,470 MW to 2,030 MW).[28]

In my view, the current uncertainties surrounding the future of trade tariffs should not prevent the Commission from granting the Companies' requested CPCN for Cane Run BESS. Denying the CPCN would prematurely foreclose the possibility of having a least-cost resource if the right conditions eventuate; granting it would allow the Companies to proceed prudently, making only those decisions and investments along the way that had to be made at that time. One of the benefits of the analysis the Companies have performed is that they understand and have informed the Commission what two relevant measures of prudence would be, i.e., levels of ITC and trade tariff effects. This should allow the Commission to grant the requested CPCN with a high

[26] *See, e.g.,* Companies' Response to PSC 3-8(b), Attachment 1 at 14, Table 7.
[27] *See* Case No. 2024-00326, IRP Vol. III, 2024 IRP Resource Assessment at 44-48.
[28] Companies' Response to PSC 3-8(b), Attachment 1 at 14, Table 7. Note that the Companies' analysis assumed the "Ozone NAAQS" only environmental regulatory scenario. Other environmental regulations might affect the analysis, though it currently appears unlikely.

degree of confidence in its ability to evaluate in an informed way the prudence of the Companies' actions pursuant to the granted CPCN authority.

Q. Certain intervenor witnesses criticize Cane Run BESS as being inadequate to serve high load factor loads like data centers.[29] Does this criticism misunderstand the role of BESS in the total resource portfolio?

A. Yes. BESS is not an energy-generating resource; rather, it moves energy produced by other resources in time, allowing those resources, whatever their fuel or energy source, to produce and store energy when their output is not required to meet instantaneous demand. BESS can then act as a limited-duration peaking resource or provide other services as needed. Contrary to what certain intervenor witnesses have stated or implied, at no point have the Companies represented that BESS would be an around-the-clock energy serving or producing resource; rather, BESS would make fuller use of existing and planned resources to reduce the need for additional fully dispatchable resources that would otherwise be required to meet peaking needs.

BESS is also a valuable resource for meeting the ramp schedule anticipated for data center customers because the Companies can add it relatively quickly and without regard for particular fuel supply or delivery constraints.

Q. AG-KIUC witness Leah Wellborn asserts that having PROSYM charge and discharge profiles and "energy margins" are necessary to evaluate the economics of BESS.[30] Is she correct?

A. No. Although I do not disagree that the cost of the energy stored and discharged matters, the hourly calculations of those costs across 8,760 hours per year carried out

[29] Chiles at 16-18; Wellborn at 21-22.
[30] Wellborn at 21.

for decades are intrinsic to the model; they are part of what the model does account for as it works to minimize total system costs. In other words, the Companies' models evaluate exactly the kinds of information about which Ms. Wellborn is concerned. Tellingly, Ms. Wellborn has expressed no criticism of the Companies' PLEXOS, PROSYM, or financial model settings or inputs. Thus, though Ms. Wellborn is certainly correct that the BESS states of charge, energy input costs, roundtrip losses, and other items are important data to evaluate BESS performance and economics, the Companies have fully addressed them all in their resource modeling, making her criticism moot.

Q. Why is Ms. Wellborn incorrect in asserting the Companies' modeling does not "affirm the reliable capacity value for the Cane Run BESS project"?[31]

A. This criticism fundamentally misunderstands the concept of capacity contribution. Indeed, it is unclear what Ms. Wellborn is trying to say in her testimony on page 22 at lines 6-14 other than to suggest that BESS is somehow less reliable than the Companies have represented by citing a variety of unrelated values and making apples-to-oranges comparisons. Interestingly, Ms. Wellborn cites to all the places the Companies have already explained these issues, but her testimony nonetheless confuses them.

Simply stated, assuming a base load forecast and a portfolio of resources to serve that load, SERVM can calculate the reliability of that portfolio in terms of loss of load expectation ("LOLE"). Adding a resource to that portfolio, e.g., 400 MW of BESS, without changing the load forecast will result in a different, lower LOLE. But adding more of the same resource (e.g., another 400 MW of BESS) will have less of an

[31] Wellborn at 22.

LOLE-reducing effect; the capacity contribution of the marginal resource is lower than the first. But contrary to Ms. Wellborn's assertions,[32] that does not mean the capacity contribution of the first resource will degrade over time. PJM's declining capacity accreditation forecast for BESS results from the forecasted addition of more batteries over time, not because the capacity contribution for a given battery is expected to decline over time. As PJM itself explains, the differences in ELCC over time have nothing to do with the reliability of the resources themselves: "Characteristics of additions are based on 25/26 membership of the ELCC Classes."[33] Rather, the different ELCC values reflect additions to or subtractions from the assumed 2025-2026 PJM portfolio. In particular, PJM explicitly noted it assumed "[s]ustained addition of wind classes, solar classes, 4-hr storage class and solar-storage hybrid classes."[34] Thus, yet again, decreasing ELCC or capacity contributions for incremental additions of particular resource types say nothing at all about the reliability of those incremental additions or the capacity contributions of previously added resources.

Therefore, there is no merit to Ms. Wellborn's assertions in this regard, and the Commission should disregard it when considering Cane Run BESS.

[32] Wellborn at 22 ln. 11-12.
[33] Patricio Rocha-Garrido, "Supplementary Information about ELCC Class Ratings calculated for DY 2027/28 – DY 2034/35" at 3, PJM (Aug. 6, 2024), available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2024/20240806/20240806-item-08---supplementary-information---elcc-class-ratings.pdf (accessed June 29, 2025).
[34] *Id.*

THE COMMISSION SHOULD REJECT JOINT INTERVENORS WITNESS SEAN O'LEARY'S FAULTY ECONOMICS AND NON-JURISDICTIONAL ASSERTIONS CONCERNING EMPLOYMENT AT NGCC FACILITIES VERSUS DSM-EE

Q. Do you have any observations concerning Joint Intervenors witness Sean O'Leary's assertions concerning the economic benefits of NGCC units versus DSM-EE programs?[35]

A. Yes. The crux of his argument is that an operating NGCC facility employs around 30 people (which is about the same number of people employed at a typical Olive Garden restaurant, according to Mr. O'Leary), whereas DSM-EE programs require many more local employees and contractors people to deploy and operate, meaning more income will stay in local communities. In addition to employment being an issue outside the jurisdiction of this Commission,[36] Mr. O'Leary's position ignores the Companies' obligation to serve all customers safely, reliably, and at the lowest reasonable cost, not to provide the highest possible employment irrespective of efficiency or cost. Unlike Mr. O'Leary, who provides no quantitative analyses to support his position, the Companies' extensive analyses in the record of this proceeding demonstrate their

[35] O'Leary at 26-29.

[36] *See, e.g., Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order at 108-09 (Ky. PSC Nov. 6, 2023) ("Further, pursuant to KRS 278.040, the Commission's jurisdiction is limited to the rates and services of utilities, so absent a clear directive, it would be illogical to assume that a statute requiring a utility to demonstrate savings to customers was intended to require the Commission to look at anything other than the rate effects of retirement decisions."); *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Order at 28 (Ky. PSC Oct. 5, 2018) ("The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service. Lacking jurisdiction over these non-energy factors, the Commission has no authority to require a utility to include such factors in benefit-cost analyses of DSM programs."); *The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Order at 4 (Ky. PSC July 8, 2011) ("[I]ssues of environmental externalities, such as air and water pollution from generating electricity and mining fuel to supply the generating plants, are all issues beyond the scope of the Commission's jurisdiction.").

proposed resources will indeed result in reliable service at the lowest reasonable cost under the assumptions we have stated (and with the caveats I discussed earlier concerning Cane Run BESS). The Commission should therefore disregard Mr. O'Leary's assertions on this issue as being outside its jurisdiction and contrary to the Companies' obligation to serve customers at the lowest reasonable cost.

CONCLUSION

Q. What do you conclude concerning the Companies' resource analysis in this proceeding?

A. I conclude that the Companies' resource analysis in this proceeding remains reasonable, and none of the intervenors' criticisms undermines it. The Companies' analysis demonstrates that the resources for which the Companies are seeking CPCNs are needed to provide reliable lowest-reasonable-cost service for the Companies' customers, both existing and new, based on the Companies' 2025 CPCN Load Forecast. The Companies' analysis considered all reasonable alternatives, and the proposed resources are reasonable and robust across a wide range of possible future circumstances, including different fuel prices and levels of demand. Therefore, I recommend the Commission grant all requested CPCNs.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director – Power Supply for Kentucky Utilities Company and Louisville Gas and Electric Company and is an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of July 2025.

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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