COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC TARIFF FILING OF KENTUCKY UTILITIES COMPANY FOR APPROVAL OF AN ECONOMIC DEVELOPMENT RIDER SPECIAL CONTRACT WITH BITIKI-KY, LLC	))))	**CASE NO. 2022-00371**

DIRECT TESTIMONY OF
STUART A. WILSON
DIRECTOR, ENERGY PLANNING, ANALYSIS AND FORECASTING
KENTUCKY UTILITIES COMPANY

Filed: February 21, 2023

INTRODUCTION

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

A. My name is Stuart A. Wilson. I am the Director of Energy Planning, Analysis and Forecasting 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 220 West Main Street, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before the Commission on a number of occasions.[1] I testified most recently in the Companies' pending certificate of public convenience and necessity ("CPCN") and demand-side management and energy efficiency application proceeding, Case No. 2022-00402.[2]

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to criticisms of KU's Marginal Cost of Service Study by Chelsea Hotaling and Stacy Sherwood, who testified on behalf of the Joint Intervenors in this proceeding.[3] I explain that the Joint Intervenors' witnesses' criticisms of the Marginal Cost of Service Study are contradictory in certain respects.

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[1] *See, e.g.,* Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Case No. 2021-00393, July 12, 2022 H.V.T. at 17:43:05-18:10:32 and July 13, 2022 H.V.T. at 08:12:49-12:05:40 (Ky. PSC Oct. 7, 2022); *Electronic Application of Kentucky Utilities Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Direct Testimony of Stuart A. Wilson (Mar. 31, 2020); *Electronic Application of Louisville Gas and Electric Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Direct Testimony of Stuart A. Wilson (Mar. 31, 2020).

[2] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Direct Testimony of Stuart A. Wilson (Dec. 15, 2022).

[3] The Joint Intervenors are Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

I further demonstrate that the marginal cost of serving Bitiki-KY, LLC's ("Bitiki") projected load during the five-year Economic Development Rate ("EDR") demand-charge discount period is significantly less than the revenues KU projects Bitiki will provide. Therefore, I conclude that Bitiki meets the Commission's EDR standard of providing revenues in excess of its marginal costs and will make a contribution to fixed costs.[4]

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits:

- Rebuttal Exhibit SAW-1: Revised Marginal Demand Cost Calculations Using 2020 NREL ATB Data
- Rebuttal Exhibit SAW-2: Revised Marginal Demand Cost Calculations Using 2021 NREL ATB Data
- Rebuttal Exhibit SAW-3: Revised Marginal Demand Cost Calculations Using Case No. 2022-00402 NGCC Data
- Rebuttal Exhibit SAW-4: Revised Marginal Demand Cost Calculations Using PJM 2026-2027 CONE Data
- Rebuttal Exhibit SAW-5: Excel File Supporting Wilson Rebuttal Tables 1-4

THE JOINT INTERVENORS' WITNESSES CONTRADICT EACH OTHER CONCERNING KU'S MARGINAL DEMAND COST

Q. Please summarize Ms. Hotaling's testimony concerning KU's Marginal Cost of Service Study.

A. Although Ms. Hotaling's testimony articulates a few criticisms of KU's Marginal Cost of Service Study, her testimony notably does not disagree with the study's methodology for calculating marginal demand cost (i.e., using the economic carrying charge to

[4] *See Investigation into the Implementation of Economic Development Rates by Electric and Gas Utilities*, Admin. Case No. 327, Order at 6-8 (Ky. PSC Sept. 24, 1990).

calculate the cost of advancing the next generating unit by one year). Also, Ms. Hotaling's testimony does not dispute the study's calculated values for marginal energy cost or coincident peak marginal transmission cost. These are broad and fundamental points of apparent agreement concerning the Marginal Cost of Service Study.

In contrast, Ms. Hotaling's criticisms of the Marginal Cost of Service Study are relatively few and narrow. They concern which cost data the study used or did not use in calculating marginal production demand cost, whether to use coincident peak rather than non-coincident peak values for marginal production demand and transmission cost due to Bitiki's high load factor, and adjusting marginal costs for the appropriate loss factor. As I discuss below, KU has already agreed it is appropriate to use coincident peak values for very high load factor customers like Bitiki,[5] and the Marginal Cost of Service Study itself states it is necessary to apply the appropriate loss factor.[6]

With regard to marginal demand cost, Ms. Hotaling's testimony asserts that the study is flawed because (1) it omits fixed operation and maintenance ("O&M") cost and firm gas transportation cost and (2) it should have used natural gas combined cycle ("NGCC") generating unit cost data from the Companies' recent CPCN filing rather than data from the National Renewable Energy Laboratory's 2020 Annual Technology Baseline ("2020 NREL ATB"): "Irrespective of the question on whether the generation asset evaluated in the Marginal Cost of Service Study aligns with the most recently filed IRP [Integrated Resource Plan], the costs used in the Marginal Cost of Service

[5] KU Response to JI 1-3.

[6] Marginal Cost of Service Study at 9 ("For evaluating an economic development offer, it would be necessary to adjust the NCP marginal cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.").

Study should incorporate the full costs that KU is assuming for the NGCC resources included in the CPCN filing."[7]

Q. How do the Joint Intervenors' witnesses contradict each other concerning the marginal production demand cost calculated in KU's Marginal Cost of Service Study?

A. Whereas Ms. Hotaling asserts that the Marginal Cost of Service Study should have "incorporate[d] the full costs that KU is assuming for the NGCC resources included in the CPCN filing,"[8] Ms. Sherwood's testimony on the same issue nominally affirms but substantively contradicts Ms. Hotaling's testimony. Early in her testimony, Ms. Sherwood states, "I support the recommendations put forward by Witness Hotaling."[9] But later in her testimony, Ms. Sherwood states:

> [T]he marginal cost analysis should be based upon the most recent Commission-reviewed Integrated Resource Plan ("IRP") that is adjusted for only known capacity changes or updated cost information. Here, KU has referred in its discovery responses to analysis done for a Certificate of Public Convenience and Necessity application that was only filed in December 2022, has not yet been approved, and is still early in the process of being adjudicated before the Commission. Although KU should have relied on the most recent information available in its marginal cost analysis, as discussed by Witness Hotaling, it cannot presuppose in its marginal cost analysis that capacity changes that have not yet been approved by the Commission will necessarily be approved.[10]

Thus, Ms. Sherwood expresses support for Ms. Hotaling's view while also opposing it, stating that the Marginal Cost of Service Study should be "based upon the most recent Commission-reviewed [IRP] … adjusted for only known capacity changes or updated

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[7] Hotaling Testimony at 10.
[8] *Id.*
[9] Sherwood Testimony at 4.
[10] *Id.* at 18-19.

cost information" while also stating that KU "cannot presuppose in its marginal cost analysis that capacity changes that have not yet been approved by the Commission will necessarily be approved."[11] It therefore seems that Ms. Hotaling believes the August 12, 2022 study filed with the Bitiki EDR contract on October 7, 2022, should have used data from a CPCN filing made on December 15, 2022, whereas Ms. Sherwood asserts the study should have used IRP data "adjusted for only known capacity changes or updated cost information," which on Ms. Sherwood's account cannot be known until the end of the CPCN proceeding, a proceeding that will almost certainly extend into the fourth quarter of this year. I address the issue of the correct data to use in the marginal demand cost calculation at length below, but it is noteworthy that the Joint Intervenors' witnesses have offered contradictory testimony on this issue, and Ms. Sherwood's testimony appears to contradict itself by both agreeing and disagreeing with Ms. Hotaling's testimony.

USING NREL ATB DATA IN THE MARGINAL COST OF SERVICE STUDY WAS REASONABLE WHEN THE PRIME GROUP CONDUCTED THE STUDY AND WHEN KU FILED THE BITIKI EDR CONTRACT

Q. Ms. Hotaling argues that the Marginal Cost of Service Study should have "incorporate[d] the full costs that KU is assuming for the NGCC resources included in the CPCN filing."[12] Do you agree?

A. No. The Marginal Cost of Service Study is dated August 12, 2022. At that time, the Companies had not received any responses to their supply-side request for proposals ("RFP"), the deadline for which was August 17, 2022. Processing the responses, following up with bidders, and conducting the necessary modeling and economic

[11] *Id.*

[12] Hotaling Testimony at 10.

analysis to create a complete supply-side portfolio proposal required additional months of work.[13] Therefore, it would have been premature at best for The Prime Group to have used NGCC bid data from the Companies' Project Engineering group in the study. At that time, the Companies could not have known what all of the RFP responses would be, and they therefore could not have known which supply-side resources, including possible environmental retrofits of their existing units, would prove to be most economical and included in the Companies' eventual CPCN application.

Q. Was it reasonable for KU to use an August 12, 2022 Marginal Cost of Service Study to support the Bitiki EDR contract filed on October 7, 2022?

A. Yes. The Commission's final Order in Administrative Case No. 327 states regarding EDR contracts, "Demonstration of marginal cost recovery should be accomplished through the use of a current marginal cost-of-service study. A current study is one conducted no more than one year prior to the date of the contract."[14] Therefore, the August 12, 2022 Marginal Cost of Service Study to support the Bitiki EDR contract, which was dated September 28, 2022, complies with this requirement. Given that the analysis of the RFP responses and formulation of a total portfolio to serve customers' needs, including both supply-side and demand-side resources, was not expected to be completed until near the end of the year, as well as the need to timely file the Bitiki EDR contract, it would not have been reasonable to delay the filing for another two to three months.

[13] *See, e.g.,* Case No. 2022-00402, Testimony of Charles R. Schram (Dec. 15, 2022); Case No. 2022-00402, Testimony of Stuart A. Wilson (Dec. 15, 2022).
[14] Admin. Case No. 327, Order at 8 (Ky. PSC Sept. 24, 1990).

I would further note that the Companies were still developing and refining their load forecast and conducting analyses regarding both supply- and demand-side resources when KU submitted the Bitiki EDR contract. I have personal knowledge of this as the person primarily responsible for the economic analyses that led to the Companies' supply-side CPCN proposals set out in the December 15, 2022 application. Therefore, it would not have been possible by October 7 to have "incorporate[d] the full costs that KU is assuming for the NGCC resources included in the CPCN filing" into a Marginal Cost of Service Study with any reasonable degree of certainty.[15] Moreover, doing so would not have met Ms. Sherwood's standard of "adjust[ing] for only known capacity changes or updated cost information."[16] It was thus reasonable for KU to have used the August 12, 2022 Marginal Cost of Service Study to support the Bitiki EDR contract.

Q. Why was it reasonable to use 2020 NREL ATB data for an NGCC unit in the Marginal Cost of Service Study?

A. When The Prime Group conducted the study, using 2020 NREL ATB data was reasonable because it was generally consistent with 2021 NREL ATB data the Companies had used in their 2021 IRP.[17] Though the 2021 NREL ATB included a higher NGCC fixed O&M cost than the 2020 NREL ATB, the NGCC overnight capital cost in the 2020 NREL ATB was higher than the same cost in the 2021 NREL ATB.[18]

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[15] Hotaling Testimony at 10.
[16] Sherwood Testimony at 18-19.
[17] *See, e.g.,* Case No. 2021-00393, IRP Vol. I at 5-11 (Oct. 19, 2021).
[18] Compare 2020 NREL ATB data ($951/kW overnight capital cost; $13/kW-year) to 2021 NREL ATB data ($919/kW overnight capital cost; $27/kW-year). 2020 NREL ATB data is available at https://atb-archive.nrel.gov/electricity/2020/files/2020-ATB-Data.xlsm; 2021 NREL ATB data is available at https://data.openei.org/files/4129/2021-ATB-Data_Master_new.xlsm.

Using data for an NGCC unit without carbon capture and sequestration ("CCS") technology was appropriate when The Prime Group conducted the Marginal Cost of Service Study because the Companies' analysis in the IRP proceeding showed that NGCC without CCS was favorable when CCS was not assumed to be mandatory.[19] Indeed, the Companies' analysis showed it was the only generating technology added absent carbon pricing (1,539 MW of NGCC capacity added), and the Companies' models added even more NGCC capacity in carbon pricing scenarios (3,078 MW at $15 and $25 per ton carbon pricing).[20] Therefore, for the purposes of the Marginal Cost of Service Study, it was reasonable to use 2020 NREL ATB data for an NGCC unit without CCS.

ACCOUNTING FOR MS. HOTALING'S RECOMMENDATIONS, BITIKI'S PROJECTED REVENUES FAR EXCEED ITS MARGINAL COSTS DURING THE EDR DISCOUNT PERIOD

Q. Do you agree that using coincident peak values and transmission-level loss adjustments is appropriate in evaluating the marginal cost of service for Bitiki?[21]

A. Yes. Regarding using coincident peak rather than non-coincident peak values for marginal demand and transmission costs, I agree it is appropriate to use coincident peak values for very high load factor customers like Bitiki. KU agreed with this point in discovery earlier in this proceeding.[22]

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[19] Case No. 2021-00393, Companies' Response to PSC 2-1(b) (Mar. 25, 2022).
[20] *Id.*
[21] *See* Hotaling testimony at 10-11.
[22] KU Response to JI 1-3.

I further agree that applying transmission-level loss adjustments is appropriate for evaluating the marginal cost of service for Bitiki. Doing so would be consistent with the text of the Marginal Cost of Service Study.[23]

But as I demonstrate below, even when accounting for these factors, Bitiki's projected revenues still far exceed its marginal costs over the EDR discount period.

Q. Ms. Hotaling's testimony states, "Nor does the Company include any costs associated with interconnection of the new unit."[24] Is that correct?

A. No. NREL's ATB data includes electrical infrastructure and interconnection costs in its capital costs, including internal and control connections, onsite electrical equipment (e.g., switchyard), power electronics, and transmission substation upgrades.[25]

Q. Should marginal production demand cost include fixed O&M and firm gas transportation costs?

A. Yes. Notably, fixed O&M values for both of the NGCC units the Companies have proposed to construct were publicly available when Ms. Hotaling's testimony was filed, and they are lower than the 2020 NREL ATB values.[26]

Regarding firm gas transportation cost, Ms. Hotaling cited a $22/kW-year cost for firm gas transportation from the Companies' 2021 IRP.[27] That value is appropriate for simple-cycle combustion turbines ("SCCTs"), but not for NGCC units without

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[23] Marginal Cost of Service at 9 ("For evaluating an economic development offer, it would be necessary to adjust the NCP marginal cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.").
[24] Hotaling Testimony at 8 lines 18-19.
[25] https://atb-archive.nrel.gov/electricity/2020/definitions.php.
[26] *See* Case No. 2022-00402, Testimony of Lonnie E. Bellar at 17 (Dec. 15, 2022) ("The annual operating cost in 2027 dollars for the Mill Creek NGCC is expected to be $3.7 million in fixed O&M costs and $1.06/MWh in variable O&M costs. The annual operating cost in 2028 dollars for the Brown NGCC is expected to be $4.2 million in fixed O&M costs and $1.08/MWh in variable O&M costs").
[27] Hotaling Testimony at 4.

CCS, which have higher capacity ratings than SCCTs at the same level of gas input capacity. The firm gas transportation cost the Companies provided for NGCC units without CCS in response to the Commission Staff's data requests in the 2021 IRP was \$19/kW-year.[28] The Companies provided that data *publicly*, not confidentially. Nonetheless, I show below and in my exhibits that Bitiki's projected revenues are still far greater than its marginal costs over the EDR discount period even using a firm gas transportation cost of \$22/kW-year.

Q. How do you propose to address Ms. Hotaling's recommendations and determine whether the Bitiki EDR contract will result in Bitiki's projected revenues exceeding its marginal cost of service?

A. To fully evaluate her recommendations, I considered them from four different perspectives. Two use data that was available and would have been appropriate to use at the time The PRIME Group conducted the study in August 2022. The third uses data from the December 2022 CPCN filing to provide an updated view. The fourth uses data from the PJM 2026-2027 Cost of New Entry ("CONE") Report cited by Ms. Hotaling and requested by the Commission Staff in discovery.[29] All of the approaches demonstrate that Bitiki's projected revenues exceed its marginal cost of service.

Q. Please describe the first approach (using 2020 NREL ATB data) and its results.

A. The first approach revises the Marginal Cost of Service Study using 2020 NREL ATB values for NGCC fixed O&M cost (\$13/kW-year) and the 2021 IRP value cited by Ms. Hotaling for firm gas transportation cost (\$22/kW-year) to arrive at a new coincident

[28] Case No. 2021-00393, Companies' Response to PSC 1-26(h) (Feb. 11, 2022).
[29] Hotaling Testimony at 8; Joint Intervenors' Response to PSC 1-1.

peak marginal demand cost of $6.12/kW-month.[30] Adding to that value the coincident peak marginal transmission cost from the Marginal Cost of Service Study of $0.02/kW-month—which Ms. Hotaling does not contest—results in a total marginal demand-based (production plus transmission) cost of $6.14/kW-month.[31] By comparison, total Rate RTS demand charges are $18.30/kVA-month, nearly three times Bitiki's marginal kW-based demand cost using this methodology.[32] Therefore, using the data described above to calculate marginal costs, Bitiki will provide revenues in excess of its marginal costs in all five years of the EDR discount period, including the first year of the EDR contract in which a 50% demand charge discount applies. More precisely, assuming 13,000 kVA of billing demand, in the first year of the EDR contract Bitiki will pay discounted demand charges of $1,427,400 and have marginal demand-related costs of $990,476 (including applicable losses),[33] making a contribution of nearly $440,000 toward fixed costs in the first year alone. As shown in Table 1 below, across the five-year EDR discount period, Bitiki will make fixed-cost contributions of more than $5 million, and Bitiki will make fixed-cost contributions of almost $14.4 million over the full ten-year term of the EDR contract.

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[30] *See* Rebuttal Exhibit SAW-1, which is a revised version of the Excel spreadsheet that supported the Marginal Cost of Service Study's marginal production demand cost values that KU provided in response to JI 1-19.
[31] Marginal Cost of Service Study at Attachment D.
[32] *See* Kentucky Utilities Company, P.S.C. No. 20, Third Revision of Original Sheet No. 25.
[33] The transmission-level loss factor for KU is 3.295%, which Ms. Hotaling recommends using. (Hotaling Testimony at 12.) Therefore, Bitki's annual marginal demand-related cost is $990,476 = (13,000 kW * 12 months * $6.14/kW-month)/(1-0.03295).

Table 1: Bitiki Revenues and Marginal Costs Using 2020 NREL ATB Data

	EDR discount level	Bitiki Demand Revenue	Marginal Demand-Related Cost	Difference (revenue minus cost)
Year 1	50%	$ 1,427,400	$ 990,476	$ 436,924
Year 2	40%	$ 1,712,880	$ 990,476	$ 722,404
Year 3	30%	$ 1,998,360	$ 990,476	$ 1,007,884
Year 4	20%	$ 2,283,840	$ 990,476	$ 1,293,364
Year 5	10%	$ 2,569,320	$ 990,476	$ 1,578,844
Year 6	0%	$ 2,854,800	$ 990,476	$ 1,864,324
Year 7	0%	$ 2,854,800	$ 990,476	$ 1,864,324
Year 8	0%	$ 2,854,800	$ 990,476	$ 1,864,324
Year 9	0%	$ 2,854,800	$ 990,476	$ 1,864,324
Year 10	0%	$ 2,854,800	$ 990,476	$ 1,864,324
Years 1-5 total				$ 5,039,419
Years 1-10 total				$ 14,361,038

Q. Please describe the second approach and its results.

A. The second approach revises the Marginal Cost of Service Study using 2021 NREL ATB values for NGCC overnight capital cost ($919/kW) and fixed O&M cost ($27/kW-year),[34] and it uses the 2021 IRP value cited by Ms. Hotaling for firm gas transportation cost ($22/kW-year) to arrive at a new coincident peak marginal demand cost of $6.90/kW-month.[35] Adding to that value the coincident peak marginal transmission cost from the Marginal Cost of Service Study of $0.02/kW-month results in a total marginal demand-based cost of $6.92/kW-month, which is less than 40% of the total Rate RTS demand charges of $18.30/kVA-month.[36] Therefore, using this

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[34] Note that the large increase in fixed O&M cost from the 2020 NREL ATB to the 2021 NREL ATB is due to a change in NREL ATB methodology, which added property taxes and insurance to fixed O&M cost. (See https://atb.nrel.gov/electricity/2021/changes_in_2021 ("The 2021 ATB represents the first time the U.S. Department of Energy (DOE) Office of Fossil Energy and Carbon Management directly contributed to an ATB update. One notable change is the inclusion of assumptions for property taxes and insurance (PT&I) as a component of fixed operation and maintenance costs.").) This change in methodology likely overstates the marginal cost for Bitiki because the Marginal Cost of Service Study includes a separate value for property taxes.

[35] *See* Rebuttal Exhibit SAW-2, which is a revised version of the Excel spreadsheet that supported the Marginal Cost of Service Study's marginal production demand cost values that KU provided in response to JI 1-19.

[36] *See* Kentucky Utilities Company, P.S.C. No. 20, Third Revision of Original Sheet No. 25.

second approach to calculate marginal costs, Bitiki will provide revenues in excess of its marginal costs in all five years of the EDR discount period, including the first year of the EDR contract. In the first year alone, Bitiki will make a contribution of over $310,000 toward fixed costs.[37] As shown in Table 2 below, across the five-year EDR discount period, Bitiki will make fixed-cost contributions of more than $4.4 million, and Bitiki will make fixed-cost contributions of over $13.1 million over the full ten-year term of the EDR contract.

Table 2: Bitiki Revenues and Marginal Costs Using 2021 NREL ATB Data

	EDR discount level	Bitiki Demand Revenue	Marginal Demand-Related Cost	Difference (revenue minus cost)
Year 1	50%	$ 1,427,400	$ 1,116,302	$ 311,098
Year 2	40%	$ 1,712,880	$ 1,116,302	$ 596,578
Year 3	30%	$ 1,998,360	$ 1,116,302	$ 882,058
Year 4	20%	$ 2,283,840	$ 1,116,302	$ 1,167,538
Year 5	10%	$ 2,569,320	$ 1,116,302	$ 1,453,018
Year 6	0%	$ 2,854,800	$ 1,116,302	$ 1,738,498
Year 7	0%	$ 2,854,800	$ 1,116,302	$ 1,738,498
Year 8	0%	$ 2,854,800	$ 1,116,302	$ 1,738,498
Year 9	0%	$ 2,854,800	$ 1,116,302	$ 1,738,498
Year 10	0%	$ 2,854,800	$ 1,116,302	$ 1,738,498
Years 1-5 total				$ 4,410,289
Years 1-10 total				$ 13,102,778

[37] The transmission-level loss factor for KU is 3.295%, which Ms. Hotaling recommends using. (Hotaling Testimony at 12.) Therefore, Bitki's annual marginal demand-related cost using this data is $1,116,302 = (13,000 kW * 12 months * $6.92/kW-month)/(1-0.03295). Projected demand revenue of $1,427,400 minus that marginal demand-related cost ($1,116,302) equals $311,098.

Q. Please describe the third approach and its results.

A. The third approach revises the Marginal Cost of Service Study using cost data from the Companies' December 2022 CPCN application and 2021 IRP proceeding,[38] all of which was publicly available at the time Ms. Hotaling's testimony was filed.[39] Specifically, the third approach uses costs for the NGCC unit the Companies have proposed to install at the E.W. Brown Generating Station, which has a higher capital cost ($700 million for a 621 MW unit, equivalent to $1,127/kW) and fixed O&M cost ($4.2 million/year, equivalent to $7/kW-year) than the NGCC unit the Companies propose to construct at the Mill Creek Generating Station.[40] Notably, the Brown NGCC capital cost is an "all in" value; it includes additional gas transmission cost and interconnection cost (as do the Mill Creek NGCC costs presented in Case No. 2022-00402).[41] Using the higher-cost Brown NGCC as the marginal unit for this analysis is appropriate because if the Bitiki EDR contract is economical compared to that unit, it would be even more economical compared to the similar but lower-cost Mill Creek NGCC.

Using those capital and fixed O&M costs, as well as the 2021 IRP value cited by Ms. Hotaling for firm gas transportation cost ($22/kW-year),[42] results in a coincident peak marginal demand cost of $6.44/kW-month. Adding to that value the coincident peak marginal transmission cost from the Marginal Cost of Service Study of $0.02/kW-month results in a total marginal demand-based cost of $6.46/kW-month,

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[38] *See* Rebuttal Exhibit SAW-3, which is a revised version of the Excel spreadsheet that supported the Marginal Cost of Service Study's marginal production demand cost values that KU provided in response to JI 1-19.
[39] Case No. 2022-00402, Testimony of Lonnie E. Bellar at 17 (Dec. 15, 2022) (capital and fixed O&M cost); Case No. 2021-00393, Companies' Response to PSC 1-26(h) (firm gas cost for NGCC without CCS).
[40] Case No. 2022-00402, Testimony of Lonnie E. Bellar at 17 (Dec. 15, 2022).
[41] *Id.*
[42] Hotaling Testimony at 4.

which is about 35% of the total Rate RTS demand charges of $18.30/kVA-month.[43] Thus, using this third approach to calculate marginal costs, Bitiki will provide revenues in excess of its marginal costs in all five years of the EDR discount period, including the first year of the EDR contract. In the first year alone, Bitiki will make a contribution of over $385,000 toward fixed costs.[44] As shown in Table 3 below, across the five-year EDR discount period, Bitiki will make fixed-cost contributions of nearly $4.8 million, and Bitiki will make fixed-cost contributions of over $13.8 million over the full ten-year term of the EDR contract.

Table 3: Bitiki Revenues and Marginal Costs Using 2022 CPCN and 2021 IRP Data

	EDR discount level	Bitiki Demand Revenue	Marginal Demand-Related Cost	Difference (revenue minus cost)
Year 1	50%	$ 1,427,400	$ 1,042,097	$ 385,303
Year 2	40%	$ 1,712,880	$ 1,042,097	$ 670,783
Year 3	30%	$ 1,998,360	$ 1,042,097	$ 956,263
Year 4	20%	$ 2,283,840	$ 1,042,097	$ 1,241,743
Year 5	10%	$ 2,569,320	$ 1,042,097	$ 1,527,223
Year 6	0%	$ 2,854,800	$ 1,042,097	$ 1,812,703
Year 7	0%	$ 2,854,800	$ 1,042,097	$ 1,812,703
Year 8	0%	$ 2,854,800	$ 1,042,097	$ 1,812,703
Year 9	0%	$ 2,854,800	$ 1,042,097	$ 1,812,703
Year 10	0%	$ 2,854,800	$ 1,042,097	$ 1,812,703
Years 1-5 total				$ 4,781,315
Years 1-10 total				$ 13,844,829

Q. Please describe the fourth approach and its results.

A. The fourth approach revises the Marginal Cost of Service Study using cost data from the PJM 2026-2027 CONE Report cited by Ms. Hotaling, specifically 1x1 NGCC cost

[43] *See* Kentucky Utilities Company, P.S.C. No. 20, Third Revision of Original Sheet No. 25.

[44] The transmission-level loss factor for KU is 3.295%, which Ms. Hotaling recommends using. (Hotaling Testimony at 12.) Therefore, Bitki's annual marginal demand-related cost using this data is $1,042,097 = (13,000 kW * 12 months * $6.46/kW-month)/(1-0.03295). Projected demand revenue of $1,427,400 minus that marginal demand-related cost ($1,042,097) equals $385,303.

data shown in Table ES-1 of the PJM 2026-2027 CONE Report, which is presented below for ease of reference:[45]

TABLE ES-1: ESTIMATED CONE FOR CC PLANTS

				1 x 1 Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,359	$1,240	$1,263	$1,308
[2]	Installed (inc. IDC)	*$m*		$1,470	$1,343	$1,367	$1,415
[3]	First Year FOM	*$m/yr*		$37	$53	$47	$39
[4]	**Net Summer ICAP**	***MW***		**1,171**	**1,174**	**1,144**	**1,133**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$1,160	$1,057	$1,104	$1,154
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$1,255	$1,144	$1,195	$1,248
[7]	Levelized FOM	*$/kW-yr*		$39	$49	$47	$42
[8]	**After-Tax WACC**	***%***		**7.9%**	**8.0%**	**8.0%**	**8.0%**
[9]	Effective Charge Rate	*%*		12.4%	12.2%	12.3%	12.3%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$182,700**	**$178,700**	**$183,100**	**$184,500**
[11]	**Levelized CONE**	***$/MW-day***	= [10] / 365	**$501**	**$490**	**$502**	**$506**

The fourth approach uses the highest unitized installed capital cost show in the table above as the capital cost ($1,255/kW).[46] Also, it uses the highest levelized fixed O&M cost shown in the same table, which includes firm gas cost ($49/kW-year).[47] Note that this approach results in higher marginal costs than using any of four cost combinations shown in the table above, making it more difficult for the Bitiki contract to show net benefits.

Using those capital and fixed O&M costs results in a coincident peak marginal demand cost of $8.26/kW-month. Adding to that value the coincident peak marginal transmission cost from the Marginal Cost of Service Study of $0.02/kW-month results

[45] Hotaling Testimony at 8. *See also* Joint Intervenors' Response to PSC 1-1.
[46] Joint Intervenors' Response to PSC 1-1, attachment at page vii.
[47] *Id. See also id.* at 25-26; Hotaling Testimony at 8.

in a total marginal demand-based cost of $8.28/kW-month, which is about 45% of the total Rate RTS demand charges of $18.30/kVA-month.[48] Thus, using this fourth approach to calculate marginal costs, Bitiki will provide revenues in excess of its marginal costs in all five years of the EDR discount period, including the first year of the EDR contract. In the first year alone, Bitiki will make a contribution of over $91,000 toward fixed costs.[49] As shown in Table 4 below, across the five-year EDR discount period, Bitiki will make fixed-cost contributions of over $3.3 million, and Bitiki will make fixed-cost contributions of over $10.9 million over the full ten-year term of the EDR contract.

Table 4: Bitiki Revenues and Marginal Costs Using PJM 2026-27 CONE Data

	EDR discount level	Bitiki Demand Revenue	Marginal Demand-Related Cost	Difference (revenue minus cost)
Year 1	50%	$ 1,427,400	$ 1,335,691	$ 91,709
Year 2	40%	$ 1,712,880	$ 1,335,691	$ 377,189
Year 3	30%	$ 1,998,360	$ 1,335,691	$ 662,669
Year 4	20%	$ 2,283,840	$ 1,335,691	$ 948,149
Year 5	10%	$ 2,569,320	$ 1,335,691	$ 1,233,629
Year 6	0%	$ 2,854,800	$ 1,335,691	$ 1,519,109
Year 7	0%	$ 2,854,800	$ 1,335,691	$ 1,519,109
Year 8	0%	$ 2,854,800	$ 1,335,691	$ 1,519,109
Year 9	0%	$ 2,854,800	$ 1,335,691	$ 1,519,109
Year 10	0%	$ 2,854,800	$ 1,335,691	$ 1,519,109
Years 1-5 total				$ 3,313,345
Years 1-10 total				$ 10,908,890

Q. Is it appropriate to use PJM CONE data to evaluate the marginal costs of serving Bitiki?

[48] *See* Kentucky Utilities Company, P.S.C. No. 20, Third Revision of Original Sheet No. 25.
[49] The transmission-level loss factor for KU is 3.295%, which Ms. Hotaling recommends using. (Hotaling Testimony at 12.) Therefore, Bitki's annual marginal demand-related cost using this data is $1,335,691 = (13,000 kW * 12 months * $8.28/kW-month)/(1-0.03295). Projected demand revenue of $1,427,400 minus that marginal demand-related cost ($1,335,691) equals $91,709.

A. No. The Companies are not PJM members and do not participate in PJM's capacity markets; PJM CONE data therefore has no effect on KU's marginal cost of service. The sole point of presenting the results of the fourth method using PJM 2026-2027 CONE data is that the Bitiki EDR contract results in projected demand revenues in excess of Bitiki's marginal demand costs even using this data set.

Q. In all your calculations above, you do not include marginal energy cost or projected energy revenues. Why is it appropriate to exclude those amounts?

A. It is my understanding that the Rate RTS energy charge comprises almost exclusively two cost elements: fuel and variable O&M. The Companies' projection of the Brown NGCC's variable O&M cost is $1.08/MWh,[50] which is lower than the system average variable O&M component of existing Rate RTS energy rates. In addition, KU recovers its full fuel cost through base energy rates and its Fuel Adjustment Clause ("FAC") mechanism, and Bitiki's billing includes FAC adjustments. Thus, Bitiki's full energy-charge revenues—including FAC adjustments—should equal or exceed its marginal energy costs. Because energy-related marginal costs and revenues should net to zero or provide a small contribution to fixed costs by Bitiki, I excluded them from the calculations above.

Q. Will Bitiki make other contributions to fixed costs not included in your calculations above?

A. Yes. Bitiki's bills include environmental cost recovery ("ECR") adjustment clause charges, which include both variable and fixed cost recovery components. Because the marginal generating unit at issue in this proceeding (the Brown NGCC) will not have

[50] Case No. 2022-00402, Testimony of Lonnie E. Bellar at 17 (Dec. 15, 2022).

ECR-related cost components, all of the fixed-cost components of Bitiki's ECR adjustment clause billing are contributions to fixed costs that I have not attempted to calculate here.

Q. What do you conclude about the marginal cost of service to Bitiki versus the revenues KU projects it will receive from Bitiki during the EDR discount period?

A. I conclude that, even after addressing all of the concerns Ms. Hotaling raised and revising the Marginal Cost of Service Study to use three different reasonable cost-data sets, it is clear that Bitiki's projected revenues will significantly exceed Bitiki's cost of service during all five years of the EDR discount period.

<u>BITIKI'S MARGINAL PRODUCTION DEMAND COST IS ARGUABLY ZERO, RESULTING IN EVEN GREATER FIXED-COST CONTRIBUTIONS FROM BITIKI</u>

Q. Is it arguable that the marginal production demand costs you calculated above are overstated and that Bitiki's fixed-cost contributions are therefore understated?

A. Yes. As the Marginal Cost of Service study notes, it would have required more than 75 MW of additional load to impact the Companies' resource plan.[51] The study further notes that the load forecast it used assumed the addition of 320 MW of load for the anticipated Blue Oval SK Battery Park; the Companies' current load projection for the battery park is 260 MW.[52] Notably, the total contract demand for all EDR contracts the Companies submitted to the Commission in 2022 is less than 35 MW, which is far less than the more than 135 MW of additional load that would be necessary to impact the Companies' resource plan.[53]

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[51] Marginal Cost of Service Study at 6-9.
[52] *See, e.g.,* Case No. 2022-00402, Testimony of Tim A. Jones at 6 (Dec. 15, 2022).
[53] 135 MW is the sum of 75 MW and 60 MW, the reduction in the Blue Oval SK load forecast.

Moreover, there are no other generating portfolio changes the Companies would make over the five-year EDR discount period resulting from adding or not adding the Bitiki load (or the total EDR load from 2022). The less than 35 MW of total 2022 EDR load would not delay any unit retirements; it would not cause the Companies to acquire any capacity.

Therefore, because the addition of the Bitiki load will not cause the Companies to advance the construction of a generating unit or make any generating portfolio changes at all over the five-year EDR discount period, it is arguable that the appropriate marginal production demand cost of Bitiki's service during that period is zero, making nearly all of Bitiki's demand-charge revenues contributions to fixed costs.

CONCLUSION

Q. What is your recommendation for the Commission?

A. I recommend the Commission find that Bitiki's projected revenues will exceed its marginal cost of service and approve the Bitiki EDR contract as beneficial for all of KU's customers.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of February, 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

APPENDIX A

Stuart A. Wilson, CFA
Director, Energy Planning, Analysis and Forecasting
Kentucky Utilities Company
Louisville Gas and Electric Company
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Louisville, Kentucky 40202
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Previous Positions (all LG&E-KU)

Manager, Generation Planning & Analysis	October 2009 – April 2016
Manager, Sales Analysis & Forecasting	May 2008 – October 2009
Supervisor, Sales Analysis & Forecasting	Aug 2006 – April 2008
Economic Analyst	Aug 2000 – July 2006
Compensation Analyst	Aug 1999 – July 2000
Business Analyst June	1997 – July 1999

Professional/Trade Memberships

CFA Society of Louisville

Education & Certifications

E.ON Emerging Leaders Program	2004-2006
CFA Charterholder	2003
LG&E Energy Leadership Development Program	1997-2002
Indiana University, Master of Business Administration	1997
University of Louisville, Master of Engineering in Electrical Engineering	1995
University of Louisville, Bachelor of Science in Electrical Engineering	1995

Civic Activities

Big Brothers Big Sisters of Kentuckiana, Board of Directors	2017 – Present
Barren Heights Christian Retreat, Board of Directors	2015 – 2021