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 APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN	)))))))	**CASE NO. 2022-00402**

RESPONSE OF
KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
THE COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION
DATED FEBRUARY 17, 2023

FILED: MARCH 10, 2023

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of March 2023.

Judy Schooler

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John Bevington**, being duly sworn, deposes and says that he is Director – Business and Economic Development for LG&E and KU Services Company, 220 West Main Street, Louisville, KY, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

John Bevington

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of March 2023.

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of March 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Vice President, Finance and Accounting, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of March 2023.

Tammy J. Elzy

Notary Public

Notary Public ID No. KYNP61560

My Commission Expires:

November 9, 2026

TAMMY J. ELZY
COMM EXPIRES 11/09/2026
NOTARY PUBLIC
ID # KYNP61560
STATE AT LARGE, KENTUCKY

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Philip A. Imber**, being duly sworn, deposes and says that he is Director – Environmental and Federal Regulatory Compliance for LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Philip A. Imber

Philip A. Imber

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8 day of March 2023.

Judy Schooler

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lana Isaacson**, being duly sworn, deposes and says that she is Manager – Emerging Business Planning and Development for Louisville Gas and Electric Company and Kentucky Utilities Company, 220 West Main Street, Louisville, KY 40202, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Lana Isaacson

Lana Isaacson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of March 2023.

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Tim A. Jones**, being duly sworn, deposes and says that he is Manager – Sales Analysis and Forecast for LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

T. A. J

Tim A. Jones

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of March 2023.

Judy Schooler

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Power Supply for LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State this 8th day of March 2023.

Juddy Schooler

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

____
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of March 2023.

____
Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

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 LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and 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 March 2023.

Judy Schooler
Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 1

Responding Witness: Lonnie E. Bellar

Q-1. Refer to the Joint Application.

a. Identify LG&E/KU's current generating units with dual fuel capabilities, and describe the dual fuel capabilities of each unit.

b. Identify LG&E/KU's current generating units with black start capabilities and describe the black start capabilities.

c. Explain whether dual fuel capabilities were considered for the proposed natural gas combined cycle (NGCC) units.

A-1.

a. LG&E and KU's current generating units with dual-fuel capabilities are Brown Units 8-11, which have full load capabilities firing either natural gas or fuel oil #2.

Generally speaking, the coal fleet is capable of generation of 10% of full- load capacity by utilizing the boiler igniters (oil or natural gas fired), which are used during unit startup before coal burners are placed in-service.

b. LG&E's black start capable unit is Cane Run 7. The site has four diesel generators capable of energizing Cane Run Station.

KU's black start capable units are the Brown Combustion Turbines Units 5-11. The nearby Dix Dam Hydro Units 1, 2, and 3 are capable of starting the Brown Combustion Turbines.

c. Dual fuel capability was not specifically included in the cost estimate developed for the proposed NGCC units. Dual fuel capability will be requested in the Request for Proposals to NGCC unit vendors as an alternative to single fuel capability.

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's First Request for Information
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Question No. 2

Responding Witness: Lonnie E. Bellar / John Bevington

Q-2. Refer to Joint Application, page 15, paragraph 19, in which stated that "As it began to appear that the Companies could have a capacity need beginning in 2028, the Companies accelerated their DSM-EE Program Plan development."

a. State whether LG&E/KU plans to conduct another Cadmus Group (Cadmus) study of cost-efficiency for proposed demand-side management (DSM) programs for the purpose of potentially amending those programs in seven years or earlier.

b. State any factors that changed between the filing of LG&E/KU's 2021 Integrated Resource Plan (IRP) in Case No. 2021-00393 and the filing of the Joint Application in this case that contributed to the proposed adoption of DSM programs excluded from the IRP.

c. State whether LG&E/KU could have previously implemented the proposed DSM programs in a cost-effective manner and why it did not.

A-2.

a. If and when the Companies propose program modifications and request Commission approval for an updated DSM portfolio plan, the Companies will perform updated cost-effectiveness calculations to assist the Commission's decision process.

b. & c. An important factor that changed between the date on which the Companies filed their 2021 IRP (October 19, 2021) and the date on which the Companies submitted their application in this proceeding (December 15, 2022) was the EPA's issuance of the draft Good Neighbor Plan (April 2022). That event significantly increased the likelihood of the Companies' anticipated 2028 capacity need. As the Companies stated in the 2021 IRP proceeding, the timing of a capacity need affects the present value of the avoided capacity cost used in DSM-EE cost-benefit calculations; the closer in time a DSM-EE program is deployed to address a capacity need, the greater the present value of the avoided capacity cost, which in turns increases the cost effectiveness of the program.[1] Thus, having greater certainty regarding the timing of the upcoming capacity need helped solidify the present value of the avoided capacity cost in the DSM-EE cost-benefit calculations.

The Companies would also note that they applied for and received Commission approval of a significant expansion of their Nonresidential Rebates program in the time between the filing of the 2021 IRP and the submission of the Companies' application in this proceeding.[2] Thus, the Companies have diligently pursued DSM-EE.

Nonetheless, developing a full DSM-EE program portfolio to the point that the Companies can seek Commission approval for it is a time-consuming undertaking. As the Companies described in the 2021 IRP proceeding, since late 2020 when the Companies first anticipated a likely capacity need in 2028 (which the Good Neighbor Plan solidified in April 2022), the Companies caused their DSM-EE consultant, Cadmus, to perform a demand response potential study in the first quarter of 2021, and the Companies further retained Cadmus in July 2021 to conduct additional program reviews precisely because the Companies anticipated an upcoming capacity need and desired to deploy cost-effective DSM-EE programming to help address that need.[3] Also, the Companies conducted a survey of their DSM-EE Advisory Group in 2021 to solicit input for developing new and updated DSM-EE programs.[4] The Companies met twice with their DSM-EE Advisory Group in 2021 as they began the DSM-EE program review and development process, and they met with the DSM-EE Advisory Group five times in 2022 as they advanced the program development process in anticipation of including the proposed DSM-EE Program Plan in the application at issue in this proceeding.[5] The Companies respectfully submit that they could not reasonably have filed a well-considered, well-analyzed, and cost-effective comprehensive DSM-EE Program Plan in consultation with the DSM-EE Advisory Group any sooner than they did.

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[1] *See, e.g.,* Case No. 2021-00393, Companies' Supplemental Post-Hearing Comments at 17 (Aug. 22, 2022), citing Case No. 2021-00393, Hearing Video Day 2 at 17:08:39-17:15:15.

[2] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of an Existing Demand-Side Management and Energy Efficiency Program*, Case No. 2022-00123, Order (Ky. PSC May 20, 2022).

[3] *See* Meeting Minutes and Presentation from the September 17, 2021 Meeting of the DSM-EE Advisory Group, available at https://lge-ku.com/dsm.

[4] *See id.*

[5] *See* Exhibit JB-2 and https://lge-ku.com/dsm for meeting minutes and presentations.

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's First Request for Information
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Question No. 3

Responding Witness: John Bevington

Q-3. Refer to the Joint Application, pages 15–16. LG&E/KU stated that in the 2024-2030 DSM-EE Program Plan, there were 39 potential programs that were considered, but that a "scoring rubric" narrowed it to 14 programs.

a. Identify and describe all 39 potential programs that were considered for the 2024-2030 DSM-EE Program Plan.

b. Explain whether LG&E/KU have considered the possibilities of implementing any of the 25 potential or proposed programs not selected for the 2024-2030 Program Plan as pilot programs.

A-3.

a. See attached. Initially, the Companies sought to create a comprehensive list of programs that could provide value to the Companies and their customers. As noted in Exhibit JB-1, the Companies identified that initial list of 39 programs by reviewing programs and successful strategies offered by utilities in other jurisdictions, surveying and meeting with the DSM Advisory Group, receiving guidance from a consultant that works nationwide on energy efficiency and demand response matters, and generating ideas from the Companies' internal stakeholders. The Companies offered the 39 programs to stakeholders for further discussion and analysis during the Advisory Group process. Using a scoring rubric that consisted of twelve weighted objectives, the Companies and Cadmus evaluated and scored all 39 programs to determine which warranted further consideration and detailed analysis. The Companies discussed this scoring rubric and filtering process with the DSM Advisory Group, specifically soliciting input from the members about which programs they would like to see move on to the next step of the analysis. This process ultimately narrowed the pool to 14 possible programs for cost-benefit analysis. After the Companies scored those 14 programs on cost-effectiveness, they presented the initial results to the DSM Advisory Group, and then modified and combined certain programs where such pairings effectively advanced common goals, re-scored the programs, shared the updated results with the DSM Advisory Group, and created final program groupings.

b. Of the programs that the Companies did not select for inclusion in the DSM/EE Program Plan, the Companies have considered the following for pilot programs: Energy Storage, Bidirectional Flow on EVs, and Managed Charging for Commercial Fleets. Additionally, the Companies discussed with the DSM Advisory Group a pilot program for research on low-income solar applications. The Companies also separately considered the potential for a smart home pilot. Ultimately, given the complexity to develop these programs and engage a meaningful number of participants, coupled with the need to proceed with scaling programs to assist with the 2028 capacity need, the Companies determined not to pursue pilot programs at this time.

The attachment is being provided in a separate file.

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's First Request for Information
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Case No. 2022-00402

Question No. 4

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-4. Refer to the Direct Testimony of Lonnie E. Bellar (Bellar Direct Testimony), page 10, lines 20–21, and page 11, lines 1–7. Since the NGCC units are replacing base load coal units, presumably they will run at a high load factor. With the variability of solar generation output, explain why the simple cycle combustion turbines (SCCT) would not be the units that ramp up and down following the solar output variability.

A-4. Generation units that have been committed to operate are controlled in real-time by the Companies' Energy Management System ("EMS") based on each unit's heat rate, fuel costs, and operating parameters such as ramping capability. SCCTs are used as peaking generation but are not routinely committed daily. On days when SCCTs are not committed, coal and NGCC units are and will be used to follow load.

Also, the proposed NGCC units will be capable of ramping to adjust for changes in solar output variability far more quickly than the Companies' existing SCCTs. The ramp rate of the proposed NGCC units is in the range of 50 MW to 80 MW per minute, whereas the ramp rate of the Companies' existing SCCT fleet is 6 MW to 10 MW per minute.

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's First Request for Information
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Question No. 5

Responding Witness: Lonnie E. Bellar

Q-5. Refer to Bellar Direct Testimony, page 11, lines 19–23.

a. Provide an update on the development of hydrogen as a viable NGCC fuel.

b. Explain how LG&E/KU would get sufficient supplies of hydrogen to its NGCC units.

c. Explain whether LG&E/KU's current SCCT fleet can utilize hydrogen and whether next generation SCCTs will be equipped to burn hydrogen.

A-5.

a. The NGCCs proposed by the Companies will have the ability to burn between 30-50% hydrogen by volume. Hydrogen blending has been tested up to 20% by Southern Company's Georgia Power Plant McDonough-Atkinson in partnership with Mitsubishi Power and the Electric Power Research Institute (EPRI). Current R&D by OEMs is focused on increasing the hydrogen blending capability beyond 50% to 100%.

b. A hydrogen production or transportation system does not yet exist to either Mill Creek or E.W. Brown. The Bellar Testimony refers to a future scenario being pursued by the federal government where hydrogen becomes economically viable and there is a "cost effective hydrogen supply resource." In this hypothetical future scenario, the hydrogen could be produced and consumed on-site or transported in from another location.

c. The current SCCT fleet can accept a 5% hydrogen blend by volume. Higher ratios of hydrogen would require significant capital investment. The next generation of advance class SCCTs will be capable of combusting between 30-50% hydrogen (by volume) according to the three OEMs (Mitsubishi, GE and Siemens).

KENTUCKY UTILITIES COMPANY
AND
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Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 6

Responding Witness: Robert M. Conroy / Christopher M. Garrett

Q-6. Refer to the Direct Testimony of Robert Conroy (Conroy Direct Testimony), page 2, line 19, discussing "[h]ow do the Companies plan to finance the NGCCs, solar facilities, and battery facilities they are proposing."

a. Explain whether LG&E/KU have considered the Energy Infrastructure Reinvestment (EIR) Program for financing these facilities or potential alternatives. If not, explain why it was not considered.

b. Confirm that the EIR Program was created by the Inflation Reduction Act (IRA) and provides up to $250 billion in loan guarantees to "enable operating energy infrastructure to avoid, reduce, utilize or sequester air pollutants or anthropogenic emissions of GHG."

A-6.

a. The Companies have had preliminary discussions with representatives from the DOE on the potential availability of financing related to these projects. The Companies believe a portion of these projects may qualify and will continue to evaluate whether financing alternatives from the EIR are cost beneficial to ratepayers and provide an efficient path to procuring low-cost financing compared to other available alternatives. As noted in Mr. Conroy's testimony (page 3, lines 3-6), the Companies will continue to evaluate financing alternatives as these projects progress and will seek the approval of the Commission pursuant to KRS 278.300 to the extent required.

b. Based upon information obtained from preliminary discussions with representatives from the DOE, the Companies confirm that the statement appears to be accurate.

KENTUCKY UTILITIES COMPANY
AND
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Response to Commission Staff's First Request for Information
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Question No. 7

Responding Witness: Robert M. Conroy

Q-7. Refer to the Conroy Direct Testimony, page 7, lines 19–21.

a. Explain why LG&E/KU feel it is appropriate to use the 50-basis point addition from their most recent rate on equity (ROE) in this case.

b. Describe how LG&E/KU has encouraged DSM incentives from this 50-basis point addition from Case No. 2017-00441.[7]

c. Explain why an ROE witness was not provided for the DSM portion of this case.

A-7.

a. The DSM Capital Cost Recovery component ("DCCR") was added to the Recovery Component ("DSMRC") in the November 9, 2011 Order in Case No. 2011-00134[8]. The DCCR was established to better value the capital expenditures previously expensed as part of the Residential and Commercial Load Management/Demand Conservation Programs. As these costs had historically been expensed through the DSM mechanism with incentives calculated through the DSMI, the Companies utilized a ROE of 10.50 percent allowed by the Commission in Case No. 2009-00548 and Case No. 2009-00549. These program costs were then removed from the DSMI component as part of Case No. 2011-00134.

[7] Case No. 2017-00441, 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 (Ky. PSC Oct. 5, 2018).
[8] Case No. 2011-00134, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of new Demand-Side management and Energy Efficiency Programs.

In Case No. 2014-00003[9], the Companies requested and received a Commission Order awarding the DCCR to be calculated with a 10.50% ROE as compared to the awarded 10.25% ROE in the general rate proceedings[10]. The Companies' argument regarding the reasonableness of the higher ROE, which the Commission agreed to as reasonable in its Order, referenced KRS 278.285(1)(c), which states that a factor to be considered when reviewing a utility's DSM plan is "[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," and KRS 278.285(2)(b), which provides that the Commission may approve DSM programs that include "incentives designed to provide financial rewards to the utility for implementing cost-effective demand-side management programs."

As discussed within the October 5, 2018 Order and the Companies' response to Commission Staff's First Request for Information, Question No. 13 in Case No. 2017-00441, the Companies proposed a 10.20% return on equity ("ROE") for capital invested in DSM-EE programs. The Commission-approved ROE for the DSM Capital Cost Recovery component of 10.50% in the prior case. The only ROE the Commission approved for the Companies in their rate cases immediately prior to the Commission's final order in the Companies' most recent rate cases was 10.00%, i.e., the DSM Capital Cost Recovery incentive was, practically speaking, 50 basis points. When the Commission approved a base-rate ROE for the Companies of 9.70% effective July 1, 2017, the DSMEE incentive effectively increased to 80 basis points. The Companies believed it was appropriate to reduce that incentive and return to the 50 basis-point incentive level that existed prior to the Commission's most recent base-rate orders for the Companies and the Commission agreed (see Ordering Paragraph 4 of the Commission's October 5, 2018 Order).

In addition, the incentive is rooted in KRS 278.285, which twice states the Commission may find reasonable and approve a utility's DSM-EE proposals, which may include "incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs."[11] These provisions are clear that the Commission should not just permit ordinary cost recovery and ROEs for DSM-EE

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[9] Case No. 2014-00003, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of new Demand-Side Management and Energy Efficiency Programs (Ky. PSC Nov. 14, 2014).

[10] Case No. 2012-00221, Application of Kentucky Utilities Company for and Adjustment of its Electric Rates (Ky. PSC Dec. 20,2012), and Case No. 2012-00222, Application of Louisville Gas and Electric Company for and Adjustment of its Electric and Gas Rates, as Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Riser, and a Gas Line Surcharge (Ky. PSC Dec. 20, 2012)

[11] KRS 278.285(1)(c) - (2)(b)

investments, but also provide positive financial incentives to encourage such investments. The Commission has consistently done so, permitting the Companies to earn incentives on their DSM-EE-program non-capital expenditures.[12] Therefore, the use of an additional 50-basis points from the most recent rate of equity ("ROE") for the Companies' DSM-EE programs is consistent with KRS 278.285's clear guidance and the Commission's long-established practice concerning providing utilities a financial incentive to implement DSM-EE programs. Moreover, because the Companies are not currently seeking any incentive for operating and maintenance costs related to DSM-EE capital projects, the ROE is the only incentive the Companies receive for such programs.

b. The 50-bps adder as discussed in response to part a. is to incentivize the Companies to offer DSM programs to their customers. As these programs are designed to reduce electric and gas usage by customers, the combination of the Lost Sales. DSMI, and DCCR components of the DSM mechanism are set up to allow cost recovery and provide a financial benefit to the utility for providing such programs. The Companies have supported Demand Side Management and Energy Efficiency programs since the early 1990's. The incentive structure has ensured the Companies continue to seek opportunities for customers to better manage their usage.

c. As described in part (a) above, in DSM cases, the Commission has historically used the most recent base rate ROE established in the Companies' most recent base rate cases to establish an ROE for DSM. This methodology has allowed the Companies to avoid the cost of engaging an expensive ROE expert witness for every DSM case, which savings benefit customers. Given the Commission's historical approach, there was no need to engage an ROE expert for this matter, and, instead, it is more efficient to establish an ROE in this proceeding using the most recent base rate ROE of 9.425 (from Case Nos. 2020-00349 and 2020-00350) plus a 50-basis point incentive as Mr. Conroy explains at page 7 of his testimony. Additionally, based on ROE trends, it is likely that an ROE witness would have recommended an ROE higher than the 9.425 from Case No. 2020-00349 and 2020-00350. In those cases, relying on data from S&P Global Market Intelligence, the Commission adjusted the stipulated ROE of 9.55 downward to 9.425 based on a downward trend in ROEs from 2019 to 2020.[13] But ROE data from 2021 (when those rate cases were decided) compared to ROE from 2022 shows an upward trend. For all electric utilities, the average ROE for 2021 was 9.38 and for 2022 it was 9.54. For vertically integrated electric utilities, the average ROE for 2021 was 9.53 and for 2022 it was 9.69.

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[12] *See* Kentucky Utilities Company, P.S.C. No. 20, Original Sheet Nos. 86.1 and 86.2; Louisville Gas and Electric Company P.S.C. Electric No. 13, Original Sheet Nos. 86.1 and 86.2; Louisville Gas and Electric Company P.S.C. Gas No. 13, Original Sheet Nos. 86.1 and 86.2

[13] Case Nos. 2020-00349 and 2020-00350, June 30, 2021 Orders, p. 21 and 24, respectively.

KENTUCKY UTILITIES COMPANY
AND
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Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 8

Responding Witness: Philip A. Imber

Q-8. Refer to the Direct Testimony of Phillip Imber (Imber Direct Testimony), page 4, lines 6–8. Identify LG&E/KU's coal-fired generating units that are equipped with Selective Catalytic Reduction equipment.

A-8. The following units are equipped with Selective Catalytic Reduction (SCR) equipment:

Mill Creek Generating Units 3 and 4;
Ghent Generating Units 1, 3 and 4;
EW Brown Generating Unit 3;
Trimble County Generating Units 1 and 2.

KENTUCKY UTILITIES COMPANY
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Question No. 9

Responding Witness: Philip A. Imber / Stuart A. Wilson

Q-9. Refer to the Imber Direct Testimony, page 4, lines 14–18. Provide the annual projected emissions and projected allocations for each unit planned to be retired, for 2023 through 2030, assuming continued operation of the units.

A-9. See the tables below. The projected NO_x allocations are from the Good Neighbor Plan ("GNP"). The allocation numbers for 2023 and 2024 are values provided by the EPA. The prorated value the EPA provided for 2023 assumes the rule is effective in mid-May. The 2026 value was provided by the EPA as an estimate of allocations that will be available upon the implementation of SCR controls on all non-SCR units. The allocations for 2025 will be based on the heat input to units in 2023; the number provided in the table depicts allocations will be less than 2024 as a result of dynamic budgeting and bank recalibration. In 2027 and beyond, the dynamic budgeting, bank recalibration, and backstop limit will cause allocations to decline over time.

Ghent Unit 2 Ozone Season NO_x Emissions

Year	Forecasted Ozone Season NO_x Emissions by Fuel Price Scenario (tons)						Projected NO_x Allocations (tons)
	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG	High Gas, Curr CTG	
2023	1,827	1,822	1,838	1,805	1,838	1,784	606 (621 prorated)
2024	1,700	1,707	1,749	1,669	1,727	1,658	606
2025	862	901	905	854	925	657	<606
2026	224	221	220	221	226	211	338
2027	223	221	224	220	225	213	<338
2028	223	227	227	223	227	222	<338
2029	223	224	226	221	227	219	<338
2030	212	211	214	216	214	209	<338

Mill Creek Unit 2 Ozone Season NO_x Emissions

Year	Forecasted Ozone Season NO_x Emissions by Fuel Price Scenario (tons)						Projected NO_x Allocations (tons)
	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG	High Gas, Curr CTG	
2023	1,243	1,175	1,143	1,233	1,154	1,093	328 (337 pro-rated)
2024	1,320	1,199	1,208	1,288	1,231	1,140	328
2025	619	656	672	626	661	678	<328
2026	177	175	171	178	174	165	183
2027	193	183	183	191	182	173	<183
2028	193	185	178	193	181	169	<183
2029	187	179	173	186	175	165	<183
2030	184	181	175	186	177	163	<183

Brown Unit 3 Ozone Season NO_x Emissions

Year	Forecasted Ozone Season NO_x Emissions by Fuel Price Scenario (tons)						Projected NO_x Allocations (tons)
	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG	High Gas, Curr CTG	
2023	63	95	119	64	127	85	307 (314 prorated)
2024	119	128	130	125	130	108	307
2025	160	157	162	158	166	140	<307
2026	121	120	125	119	128	112	171
2027	129	130	133	129	136	108	<171
2028	126	132	133	125	133	106	<171
2029	113	115	120	113	121	97	<171
2030	116	110	114	114	118	103	<171

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Question No. 10

Responding Witness: Philip A. Imber

Q-10. Refer to the Imber Direct Testimony, page 4, lines 20–23. Provide a copy of LG&E/KU's comments and the status of LG&E/KU's request to the EPA to revise the Good Neighbor Plan.

A-10. EPA Docket ID EPA Docket ID EPA-HQ-OAR-2021-0668 contains the Companies' comments; links are provided herein. EPA is required to respond to comments in the docket when publishing a final rule. Final rule is anticipated in the second quarter of 2023.

GNP comments Docket EPA-HQ-OAR-2021-0668:
Companies: https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0408
Midwest Ozone Group: https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0198
https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0241
https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0003
https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0323

Proposed rule published December 30, 2019 at 84 FR 71854 Docket EPA-R04-OAR-2019-0156:
Midwest Ozone Group: https://www.regulations.gov/comment/EPA-R04-OAR-2019-0156-0021

Proposed Revised CSAPR Update 85 FR 68964, 68981Docket EPA-HQ-OAR-2020-2072:
Companies: https://www.regulations.gov/comment/EPA-HQ-OAR-2020-0272-0146
Midwest Ozone Group: https://www.regulations.gov/comment/EPA-HQ-OAR-2020-0272-0139

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Question No. 11

Responding Witness: Philip A. Imber

Q-11. Refer to the Imber Direct Testimony, page 5, lines 11–12. Provide any updates to the Good Neighbor Plan.

A-11. There are no official updates to the GNP at this time.

See the response to Question No. 10; the final rule is anticipated in the second quarter of 2023.

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Question No. 12

Responding Witness: Philip A. Imber / Stuart A. Wilson

Q-12. Refer to the Imber Direct Testimony, page 8. Provide the specific assumptions in the Resource Assessment for greenhouse gas emissions standards for existing generating units stated to align with the repealed Affordable Clean Energy Rule.

A-12. No specific assumptions related to the repealed Affordable Clean Energy Rule are included in the Resource Assessment. The rule was repealed prior to submittal of the CPCN application. No further rules related to existing source GHG emissions have been proposed. The Companies modeled CO_2 regulations using scenarios that included a CO_2 emissions cost.

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Question No. 13

Responding Witness: Philip A. Imber

Q-13. Refer to the Imber Direct Testimony, page 9, lines 11–24.

a. Explain whether LG&E/KU's assertion that its reportable emissions of carbon dioxide equivalent of greenhouse gases are less than 25,000 metric tons per year includes the three coal units with the addition of SCRs.

b. Explain how the pricing of methane emissions is related to the pricing of carbon dioxide emissions for modeling purposes.

A-13.

a. LG&E/KU's position referenced in the data request does not include Mill Creek 1, Mill Creek 2, or Ghent 2. The IRA methane emissions trigger is specific to applicable facilities pursuant to subpart W of part 98 of title 40, Code of Federal Regulations. Coal fired units are not applicable.

b. The IRA related reference to methane emissions on p. 9 of Imber Direct Testimony is not related to carbon dioxide pricing related to electric generating unit emissions.

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Question No. 14

Responding Witness: Philip A. Imber

Q-14. Refer to the Imber Direct Testimony, page 9, lines 22–24. Provide LG&E/KU's reportable emissions of carbon dioxide equivalent to greenhouse gases.

A-14. The following is the 40 CFR Part 40 Subpart 98 data from the electronic Greenhouse Reporting Tool's Facility Level Information on Green House gasses Tool (FLIGHT) interactive tool:

https://ghgdata.epa.gov/ghgp/service/facilityDetail/2021?id=1002701&ds=L&et=&popup=true

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Question No. 15

Responding Witness: Philip A. Imber

Q-15. Refer to the Imber Direct Testimony, page 10, line 23 through page 11, line 2. Provide the current status of LG&E/KU's Title V air construction permit.

A-15. Title V permit applications for each NGCC were submitted to the Kentucky Division for Air Quality and the Louisville Metro Air Pollution Control District on December 15, 2022. Those applications are administratively complete and are currently under review by these respective agencies and construction permits have not been issued.

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Question No. 16

Responding Witness: John Bevington / Stuart A. Wilson

Q-16. Refer to the Direct Testimony of John Bevington (Bevington Direct Testimony), page 2, lines 17–19.

a. Provide the avoided capacity and energy values used to determine the cost-effectiveness of the DSM programs.

b. Explain in detail the methodology for calculating the avoided capacity and energy values.

A-16.

a. See the two files in Isaacson's Exhibit LI-6: "AvoidedCostsElecCONFIDENTIAL.xlxs" and AvoidedCostsGasCONFIDENTIAL.xlxs" for the requested values.

b. See Exhibit LI-6: Confidential.zip\Granular Files - CONFIDENTIAL\Data Companies Provided to Cadmus – CONFIDENTIAL\20220718_LAK_AvoidedCapacityCost CONFIDENTIAL.pdf.

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Question No. 17

Responding Witness: John Bevington

Q-17. Refer to the Bevington Direct Testimony, page 8.

a. Provide a complete list of the 39 possible programs considered and the scores each received under LG&E/KU's scoring rubric. Provide the detailed scoring results from each of LG&E/KU's evaluators and from each of Cadmus' evaluators.

b. Provide the results of the preliminary cost-benefit analysis conducted on the pool of 14 programs mentioned on lines 18–20. Provide any supporting workpapers used to conduct this cost-benefit analysis.

c. Explain which programs were combined for the second round of analysis, and why they were combined.

d. Explain why the initial screening of the 39 programs was performed to eliminate some of the 39 programs rather than conducting a cost-benefit analysis on all these programs.

A-17.

a. See the attachment provided in response to Question No. 3(a).

b. See the attached files containing the results of the preliminary cost-effectiveness analyses as well as the support file. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

c. Some of the programs within the pool of 14 programs were not cost-effective when scored individually. The DSM Advisory Group expressed strong interest in some of those programs, and the Companies ultimately desired to optimize their DSM programs offerings. So, as an additional step, the Companies sought to identify programs that function similarly, that are common in their intent, or that could be delivered similarly, and combined them together for further cost-effectiveness evaluation. The Companies ultimately grouped the following programs:

- Single family low-income weatherization and whole-building multi-family were grouped within Income-Qualified Solutions;
- Nonresidential Rebates, Small Business Audit & Direct Install, and Nonresidential Midstream Lighting were grouped within Business Solutions; and
- Optimized Charging, Bring-Your-Own-Device, Online Transactional Marketplace, and Residential and Small Nonresidential Demand Conservation were grouped within Connected Solutions.

d. See the response to Question No. 3(a) and Exhibit JB-1, Section 1.3, pages 9-12. The list of 39 programs is not representative of 39 unique, stand-alone program offerings. Instead, there are several within the list of 39 that are variations of each other whereby it would be duplicative to proceed with cost-effectiveness testing on each program variation. Additionally, the cost-effectiveness evaluation is a time intensive and complex process. Before a program can be evaluated for cost-effectiveness, for instance, the Companies must develop and determine the applicable customer group and the associated measures, customer participation estimates by year, estimated energy and demand savings by measure and year, incentive method and incentive amount(s), and the supporting elements to deliver an effective program (i.e. marketing, software, direct labor count and cost, outside services) for each program or program variation. The Companies employed the scoring rubric and initial filtering process to ensure that all parties involved in the process effectively and efficiently spent the vast majority of their time and resources on the programs that presented high value related to 12 key scoring objectives and were of particular interest to the DSM Advisory Group, Commission, or the Companies.

Notably, one of the "high priority" scoring objectives used in the rubric asked: "Is there evidence the program could be cost-effective?" Thus, the evaluators considered whether a program was offered in a broader market in a cost-effective manner as one of the filtering criteria.

The Companies performed the cost-benefit analysis on all programs with a final score of 70-100 in the rubric process. Importantly, the Companies also performed a cost-benefit analysis for certain programs that scored below 70 but were of particular interest to stakeholders or the Commission.

The attachment is being provided in a separate file.

The entire attachment is confidential and provided separately under seal.

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Question No. 18

Responding Witness: John Bevington

Q-18. Refer to the Bevington Direct Testimony, page 8–10, regarding 39 possible DSM programs evaluated.

a. Identify which of these programs were rejected during the "rubric process."

b. Provide the six program evaluator scores and total score for all 39 DSM programs evaluated.

c. Explain whether LG&E/KU and Cadmus considered any other factors to include in the rubric. If so, identify and explain those factors.

A-18.

a. See the attachment provided in response to Question No. 3(a), which includes all 39 programs, including those that did not advance beyond the rubric process for cost-effectiveness modeling. The Companies will continue to research, review, and investigate the programs not currently proposed for consideration in the future.

b. See the attachment to Question No. 3(a).

c. No, the Companies determined that the 12 objectives used in the rubric were comprehensive in terms of setting the criteria for the filtering process. To achieve consistency in the rubric process, the objectives were clearly defined so that all scorers considered the same factors in their review. It is important to note, however, that the rubric score was not the sole determining factor with respect to which programs moved to the next step. In addition to those programs that scored highly on the rubric process, the Companies advanced to the cost-effectiveness stage certain programs that are of particular interest to the DSM Advisory Group or the Companies.

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Question No. 19

Responding Witness: John Bevington

Q-19. Refer to the Bevington Direct Testimony, page. 14, lines 17–20. LG&E/KU stated that after thoroughly evaluating the Pay-As-You-Save (PAYS) program, LG&E/KU determined that it would not generate cost-effective savings.

a. Explain whether LG&E/KU considered weighting cost-effectiveness more than customer savings in this specific scenario of considering the PAYS program.

b. Explain in further detail how the IRA creates the possible influx of financing options for LG&E/KU's customers.

A-19.

a. No. The Companies evaluated cost-effectiveness of the PAYS program consistently with how they evaluated cost-effectiveness for other programs.

b. During the DSM Portfolio Plan development process, the Companies learned that the IRA may provide energy efficiency programming and financing for states and governmental entities. Also, in collaboration with the Energy and Environment Cabinet during the Plan development process, the Companies became aware that the state was evaluating financing programs funded through the IRA and the possibility of a nationwide "Greenbank."

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Question No. 20

Responding Witness: Lana Isaacson

Q-20. Provide a cost-benefit analysis for the following eliminated programs:

a. Midstream HVAC Rebates;

b. Downstream Rebates;

c. Home Energy Reports;

d. Small Business Energy Reports;

e. New Home Construction Rebates;

f. LED Streetlight Retrofits; and

g. Strategic Energy Management.

A-20. The Companies do not currently have the requested information, as these programs did not advance to the cost-effectiveness step in their program development. As noted in response to PSC 1-17(d), performing cost-effectiveness testing on potential programs is an extensive process primarily because specifying and developing the program parameters necessary to perform cost-benefit tests is an extensive and time-consuming process. Therefore, as explained in the responses to Question Nos. 3 and 17, the Companies utilized a thorough process to determine which programs to run through cost effectiveness testing, ultimately performing the testing on programs that scored highest in the rubric process, or that were of particular interest to the DSM Advisory Committee, the Commission, or the Companies.

Regarding the programs named in the subparts of this request:

a. Midstream HVAC Rebates and/or Downstream Rebates are essentially alternatives to the rebates already included in the proposed Plan

(Residential Online Audit). The Companies' proposed option includes an educational aspect through an online audit, which provides additional value to the customer. The DSM Advisory Group members also strongly advocated for the audit option. Therefore, the Companies have not initiated program development or cost-benefit testing for the program named in this subpart but will do so if the Commission requests it.

b. See response to subpart a. above.

c. Home Energy Reports program is an educational program previously offered by the Companies via a Smart Energy Profile Program ("SEP") as part of Case No. 2011-00134. A Home Energy Reports program would be an alternative to the Residential Online Audit tool, which, as described in subpart a above, will provide residential customers with the opportunity to learn more about their energy profile and steps they can take to lower their energy usage. While the proposed method of delivery (online) is different than the prior delivery method from the SEP program (physical mail), education is at the center of both programs. Therefore, the Companies have not initiated program development or cost-benefit testing for the program named in this subpart but will do so if the Commission requests it.

d. Small Business Energy reports is an alternative to the Companies' proposed Small Business Audit and Direct Install program. The Companies adopted their current proposal so they could engage one-on-one with their small business customers at their place of business versus mailing a report, which is less effective and less personal for the customers. The Companies' proposed program is cost-effective. Therefore, the Companies have not initiated program development or cost-benefit testing for the program named in this subpart but will do so if the Commission requests it.

e. The Companies offered a New Home Construction Rebates program under the name "Residential New Construction Program," which was launched in 2008 as part of Case No. 2007-00319 and continued through 2014. The Commission approved the Companies' request to cease the program in Case No. 2014-00003, at which time the Companies had achieved maximum results. The Companies will perform a cost-effectiveness evaluation for this program.

f. The Companies did not perform a cost-effectiveness analysis for LED Streetlight Retrofits because their current peak periods occur in the daytime and this program provides nighttime reductions. The Companies will perform a cost-effectiveness evaluation for this program.

g. A Strategic Energy Management offering is similar to the Companies' proposed Business Solutions – Nonresidential Rebates program, which provides non-residential customers with the option to engage with the Companies' third party contractor to identify opportunities for energy savings, assist with energy savings calculations, and assist with a rebate application process. Because of the similarities of the Business Solutions – Nonresidential Rebates program and the Strategic Energy Management offering, the Companies did not perform a cost-effectiveness analysis. The Companies will perform a cost-effectiveness analysis for this program.

For the three programs named in subparts e., f., and g. above, the process of designing and developing the program parameters and then performing cost-benefit testing will take approximately seven weeks to complete. The Companies will supplement this response when the results are final.

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Question No. 21

Responding Witness: John Bevington

Q-21. Refer to the Bevington Direct Testimony, Exhibit JB-1, Appendix B. Explain why costs under the Total Resource Cost (TRC) test were lower than the Program Administrator Cost (PAC) test in some cases (e.g., Connected Solutions, Peak Time Rebates, Demand Response).

A-21. As defined by the California Standard Practice Manual, the PAC Test includes incentive costs in the cost category while the TRC score does not. See Exhibit JB-1, page 19, Table 1-3, which illustrates this distinction. Because incentive costs are "paid back" to customers, they are not included (can also be described as "offset") in the TRC calculation.

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Question No. 22

Responding Witness: John Bevington

Q-22. Refer to the Bevington Direct Testimony, page 11.

a. Explain why TRC test was used rather than the PAC test, or some other test.

b. Explain whether the TRC test includes factors that do not affect rates or service.

A-22.

a. The Companies performed all four Commission-required cost-benefit tests on the proposed DSM-EE Program Portfolio.[13] The Companies' focus on the TRC test is consistent with the Commission's recent orders in the Companies' DSM-EE cases.[14] Most notably, the Commission stated in Case No. 2017-00441, "The Commission has traditionally evaluated DSM effectiveness by focusing on the Total Resource Cost ('TRC') results."[15]

b. The TRC test includes only factors that impact rates or service. As listed in Table 1-3 of Exhibit JB-1, as a summary level, the four costs and benefits the TRC test takes into account are: (1) present value of electric avoided energy

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[13] Bevington Direct Testimony at 10-11. *See also 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*, Case No. 1997-00083, Order at 20 (Ky. PSC April 27, 1998) (stating that "[a]ny 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 [Participant (PCT), Total Resource Cost (TRC), Ratepayer Impact (RIM), and Utility Cost or Program Administrator Cost (PAC) tests].).

[14] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of an Existing Demand-Side Management and Energy Efficiency Program*, Case No. 2022-00123, Order at 4 (Ky. PSC May 20, 2022) ("The proposal also results in an increased cost-benefit scores. Specifically, the Total Resource Cost (TRC) score increases to 1.60 versus 1.14 as filed in the 2017 DSM Case."); *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 29 (Ky. PSC Oct. 5, 2018) ("The Commission has traditionally evaluated DSM effectiveness by focusing on the Total Resource Cost ('TRC') results.").

[15] Case No. 2017-00441, Order at 29 (Ky. PSC Oct. 5, 2018).

and capacity costs; (2) present value of gas avoided costs; (3) program administrative and marketing costs; and (4) incremental measure costs incurred by participants. The impact of the first three items on rates or service is reasonably direct. The fourth item, participants' incremental costs, also has rate and service in at least two respects: (1) such costs are often conditions of service, i.e., they are explicit prerequisites to participating in a particular DSM-EE program; and (2) to the extent a participant does not bear a portion of the cost to participate in a DSM-EE program, other ratepayers will have to bear the cost, which in turn affects rates, or the participation will not occur, which could affect avoided costs and utility costs, which in turn affect rates. Therefore, all components of the TRC test have rate or service impacts.

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Question No. 23

Responding Witness: John Bevington

Q-23. Refer to the Bevington Direct Testimony, page 13, which discusses the role of rooftop solar in the DSM-EE portfolio. Clarify whether LG&E/KU considered incremental incentives for battery storage paired with net metering installations.

A-23. The Companies did not consider incremental incentives for battery storage paired with net metering solutions as a component for rooftop solar because, to the Companies' knowledge, rooftop solar has not been considered a demand-side resource. Going forward, the Companies are proposing to increase funding in the Market Research budget to perform research of possible DSM offerings in this area.

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Question No. 24

Responding Witness: John Bevington / Tim A. Jones

Q-24. Refer to the Bevington Direct Testimony, page 14, which states, "[T]he newly enacted Inflation Reduction Act creates the possible influx of financing options for customers."

a. Explain whether LG&E/KU included these new IRA-related financing options, including various rebates and tax credits, in the development of its DSM-EE portfolio.

b. If not, explain how LG&E/KU intend to leverage these programs.

c. Quantify the effects these financing options will have on either the DSM-EE portfolio or the underlying load forecast.

A-24.

a. During the development of the Plan, highlights of the IRA were available but specific guidance, programming, and information were still being developed by the federal government. Therefore, the IRA was considered but it was difficult to include any specificity in the planning and development process.

b. As noted on page 25 of Exhibit JB-1, the Companies intend to provide IRA consultation and education to customers serviced by the WeCare program in order to leverage available federal programming and help those customers take advantage of a comprehensive suite of assistance.

c. The Companies have not attempted to quantify the effects of particular IRA financing options or of other individual IRA programs or incentives in part because specific program guidance is still being developed; rather, the Companies accounted for assumed effects of the IRA and the Companies' proposed non-dispatchable DSM-EE programs cumulatively in the load forecast. See Section 3.4 beginning on page 16 of Exhibit TAJ-1 for a discussion around how the IRA was reflected in the load forecast.

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Question No. 25

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-25. Refer to the Direct Testimony of David S. Sinclair (Sinclair Direct Testimony), page 4, line 16, and page 9, lines 17–23.

a. The two NGCC units have a combined capacity of 1,242 MW, and the three coal units proposed to retire have a combined capacity of 1,194 MW. Explain why LG&E/KU needs any of the proposed solar facilities and PPAs.

b. Explain and demonstrate how investing in the 125 MW lithium-ion battery is more cost-effective than acquiring an appropriately sized SCCT or utilizing its current SCCT fleet.

c. If not explained above, explain how the 125 MW lithium-ion battery will be utilized operationally, including charging and discharging.

A-25.

a. The Companies' solar proposals are intended to help hedge future natural gas price volatility and reduce exposure to possible future CO_2 emissions regulations.[16]

b. See the response to Question No. 47(a) and the March 2023 update to Exhibit SAW-1 attached thereto. With the updated ITC revenue requirement calculations, the carrying cost of the 125 MW Brown BESS is comparable to the carrying cost of a 250 MW SCCT. As noted in Section 4.6.2 of Exhibit SAW-1 and in Mr. Sinclair's testimony,[17] the Brown BESS would have benefits the Companies have not attempted to quantify, including gaining operational experience with a technology at utility scale that is likely to become necessary to accommodate large-scale renewable energy resource deployments (both utility-owned and distributed), possible reductions in

[16] *See, e.g.,* Sinclair Direct Testimony at 18-19; Wilson Direct Testimony at 8, 15, 17, 28, and 30.
[17] *See* Sinclair Direct Testimony at 24-25.

SCCT starts and rapid ramping for all load-following units, and the possible avoidance of replacing a retiring SCCT in the future.

c. The Companies expect to charge the battery at times when the marginal cost of generation is low. Historically, this has been overnight, but the volume of solar generation being added to the portfolio is likely to create some low-cost charging opportunities during the middle of the day. The Companies expect to discharge the battery to serve peaking and ramping needs, particularly in the evenings when solar generation output is quickly declining. The Companies expect that the battery will support spinning reserves and in some circumstances dispatching the battery could obviate the need to start a SCCT.

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Question No. 26

Responding Witness: David S. Sinclair

Q-26. Refer to the Sinclair Direct Testimony, page 10, lines 1–6; page 23, lines 13–24; page 24, lines 1–14; and Exhibit DSS-1. Explain why LG&E/KU chose to enter into the proposed PPAs instead of owning all the solar facilities.

A-26. The responses to the Companies' RFP by the developers of the four proposed PPAs did not include the option to purchase.

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Question No. 27

Responding Witness: Lonnie E. Bellar / Charles R. Schram / David S. Sinclair

Q-27. Refer to the Sinclair Direct Testimony, page 10, lines 9–19.

a. Provide a copy of each solar PPA contract and explain the terms and prices under which LG&E/KU will take energy from each of the providers.

b. If not explained above, explain whether the interconnection upgrade costs will be the merchant solar companies' responsibility and provide the estimated costs.

c. Explain the estimated timeline in which each of the solar merchant companies (BrightNight LLC, ibV Energy Partners, and Clearway Energy) will file applications for construction certificates with the Kentucky State Board on Electric Generation and Transmission Siting (Siting Board).

d. Explain whether any of LG&E/KU's industrial customers have expressed an interest in renewable energy such that a portion of the proposed solar energy projects is in response to that interest. If so, provide the detailed information about the customer, average usage, and the extent of the discussions between LG&E/KU and those customers.

e. Refer also to the Direct Testimony of Stuart A. Wilson (Wilson Direct Testimony), Exhibit SAW-1, Appendix B, Subpart 3a, page 5.

(1) LG&E/KU are only proposing to build and own the 120 MW Mercer County facility. The 120 MW Marion County facility will be constructed as a merchant facility until LG&E/KU take possession post construction. Explain how the execution risks faced by the four solar PPA project developers will be different from that faced by the BrightNight LLC.

(2) Accounting for differences in financing, explain why LG&/E/KU's self-build plan for the Mercer County solar facility escapes the execution risks faced by the other solar developers.

(3) Further describe the solar PPA execution risk analysis, whether it was more qualitative, based on company experience and personal judgment or whether it was based on quantitative modeling.

A-27.

a. Copies of the PPAs were filed in this proceeding on March 1, 2023. The Companies are seeking confidential protection for the energy prices contained in the PPAs under a Petition for Confidential Protection filed with the PPAs. Confidentiality for these PPAs' prices is particularly important because three of the four PPAs contain price reopener provisions.

   A summary of each PPA is below. All agreements will provide must-take, non-firm energy as available, subject to specific availability guarantees based on irradiance to ensure the facilities are prudently maintained:

   i. Clearway Song Sparrow, 104 MW in Ballard County, term of 20 years.
   ii. BrightNight Gage GGSO, 115 MW in Ballard County, term of 20 years with potential price reopener in March 2024. If price reopener is invoked and agreement on a new price cannot be reached between the developer and the Companies, the PPA will terminate.
   iii. ibV Grays Branch, 138 MW in Hopkins County, term of 30 years with potential price reopener 60 days before project financing. If price reopener is invoked and agreement on a new price cannot be reached between the developer and the Companies, the PPA will terminate.
   iv. ibV Nacke Pike, 280 MW in Hardin County, term of 30 years with potential price reopener 60 days before project financing. If price reopener is invoked and agreement on a new price cannot be reached between the developer and the Companies, the PPA will terminate.

b. The Companies' Open Access Transmission Tariff ("OATT"), particularly Article 11 of the Large Generator Interconnection Agreement, governs the relationship between the Generator Owner (here, a merchant solar company) and Transmission Owner (here, the Companies) regarding a variety of topics including the cost responsibilities for customers desiring to interconnect a generating facility to the transmission system.

   Based on the OATT, the Transmission Owner has created the "Allocation of Cost for Generator Interconnections" document that is publicly available on the Companies' OASIS.[18] This document provides various interconnection configurations and explains which portions of the interconnection facilities

[18] Available at: https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/Allocation_of_Costs_for_Generator_Interconnections_-_effective_11-14-22.pdf

are paid for by the Generator Owner (specific to this response, this applies to the merchant solar companies), and which are paid for by the Transmission Owner.

The specific costs for each portion of the interconnection facilities are identified in the study process as performed by the Independent Transmission Organization. The table below provides the requested interconnection facility costs for the projects associated with the PPAs.[19]

Project Name	Generator Owner Costs for Interconnection Facilities	Transmission Owner Costs for Interconnection Facilities	Comments
Song Sparrow	$993,846	$9,801,317	None
Gage	$0	$0	The Gage Generator Interconnection Request is the second phase of a prior requested Generator Interconnection Request, thus no additional interconnection facilities are required.

Neither the Grays Branch nor Nacke Pike projects have been submitted to the Companies' Generator Interconnection Request queue. Therefore, interconnection costs are not available for these generators.

c. Based on each PPA's schedule for completion of specific milestones, the BrightNight LLC, ibV Energy Partners, and Clearway Energy projects would file applications with the Siting Board by March 31, 2025, March 31, 2024, and August 31, 2024, respectively.

d. The proposed solar projects are not in response to industrial customers' interest.

e.

(1) The contract for the BrightNight project in Marion County is essentially for a construction project. BrightNight will not have to get long-term financing based on a PPA price and the willingness of investors to fund the project over the 20 to 30 year term that the PPA providers will need to obtain. This project financing risk can be significant. Also, the construction contract nature of the BrightNight Marion County project

[19] Interconnection facility costs are a subset of total system upgrade costs potentially required to accommodate the output of a new or expanded generator. This response provides only the requested interconnection facility costs.

removes many of the solar market uncertainties discussed in Mr. Sinclair's testimony.[20]

(2) Differences in financing and cost recovery materially affect the ability to execute a solar project.[21] In addition, utilities and solar developers have different project permitting requirements that tend to reduce project execution risk for a utility.[22]

(3) The Companies' quantification of solar project execution risk is in Exhibit SAW-1, Section 4.6.1. Indeed, until December 2022, the largest solar installation in Kentucky today remains the Companies' E.W. Brown Solar Facility (10 MW),[23] notwithstanding numerous Siting Board approvals and Commission approvals related to much larger solar facilities in recent years. For example, the Companies have executed two solar PPAs for true utility-scale solar PPAs (100 MW Rhudes Creek in 2019 and 125 MW Ragland in 2021), yet neither project has received all necessary approvals, and neither is on schedule or has begun construction. The Companies are not alone: Big Rivers Electric Corporation ("BREC") received Commission approval for three solar PPAs in September 2020.[24] BREC has received termination notices for two of the contracts,[25] and the facility for the third is not yet operational. Regarding Siting Board-approved solar projects, it appears that 24 merchant solar projects have been approved by the Siting Board, but only one is in operation and one is under construction.[26] Therefore, solar project execution risk is real, and the Companies have quantified the possible impact of it in their analysis in this proceeding.

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[20] Sinclair Direct Testimony at 19:17-22, 20:1-19, 21:1-23, and 22:1-5
[21] *See* Sinclair Direct Testimony at 23-24.
[22] *See* Sinclair Direct Testimony, Exh. SAW-1 at 1.
[23] *See, e.g.,* https://www.seia.org/sites/default/files/2023-01/Kentucky.pdf.
[24] *Electronic Application of Big Rivers Electric Corporation for Approval of Solar Contracts*, Case No. 2020-00183, Order (Ky. PSC Sept. 28, 2020).
[25] BREC filed the termination notices in the post-case record of Case No. 2020-00183 on January 13, 2023. *See* https://psc.ky.gov/Case/ViewCaseFilings/2020-00183/Post.
[26] *See* https://psc.ky.gov/Home/EGTSB.

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Question No. 28

Responding Witness: Lonnie E. Bellar

Q-28. Refer to the Sinclair Direct Testimony, page 15, table 2. Explain any updated information regarding the status of OVEC and whether any discussions have taken place regarding the facility's retirement. Include in the response whether LG&E/KU have raised the issue at board or committee meetings.

A-28. The Companies are not aware of any updated information regarding the estimated minimum and maximum Generation Operating Range MW figures for 2025 and 2028 for OVEC's units from that shown in the table referenced above. The Companies are not aware of any discussions regarding retirement of the OVEC facilities, nor have the Companies raised the issue at OVEC board or committee meetings.

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Question No. 29

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-29. Refer to the Sinclair Direct Testimony, page 15, lines 5–12. Explain and demonstrate how LG&E/KU's proposed portfolio optimally blends both dispatchable and non-dispatchable resources to ensure reliability and reasonable cost. Include in the response the difference between the proposed portfolio's reasonable cost and a least cost portfolio.

A-29. For an extended explanation and demonstration of how the Companies' proposed portfolio optimally blends both dispatchable and non-dispatchable resources to ensure reliability and reasonable cost, see the 2022 Resource Assessment, Exhibit SAW-1, particularly Sections 4 and 5 and Appendix D (minimum reserve margin analysis).

Regarding the request for the difference between the proposed portfolio's reasonable cost and a least cost portfolio, the Companies respectfully disagree with the premise of the request. What is least cost on one set of assumptions about the future state of the world (including fuel prices, environmental regulations, project execution risk, and reliability requirements) could vary from what is least cost on a different set of assumptions.[27] What the Companies have proposed in this proceeding is a set of demand- and supply-side resources that are reliable and lowest cost *on the whole* across a broad range of possible future conditions. The proposed portfolio will also position the Companies and their customers well to be able to adapt to possible future changes in conditions, including the possibility of needing to be able to provide reliable service with a much greater penetration of renewable generation (both utility- and customer-owned). That is why the Companies believe their proposed total demand- and supply-side portfolio is lowest reasonable cost.

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[27] The Companies provided analyses of the relative costs of a variety of portfolios across a variety of different cost and other assumptions in Section 4 of Exh. SAW-1 (e.g., Tables 13, 17, 20, and 21).

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Question No. 30

Responding Witness: David S. Sinclair

Q-30. Refer to the Sinclair Direct Testimony, page 26, lines 17–24, and page 27, lines 1–7. LG&E/KU's testimony appears to favor creating new generation assets rather than joining a regional transmission organization (RTO).

a. Explain whether LG&E/KU's other regulated affiliates are members of PJM or any other RTO.

b. Explain whether LG&E/KU's affiliates own and operate utility scale batteries.

c. Explain why it is not possible for LG&E/KU to draw on and learn from the operational experience of its other regulated affiliates.

A-30. The Companies respectfully disagree with the characterization of the referenced Sinclair Direct Testimony that the Companies "favor creating new generation assets rather than joining a regional transmission organization (RTO)." Load serving entities in an RTO are still required to have capacity and that capacity can be owned or purchased. Also, while a load serving entity in an RTO is not directly responsible for serving the real-time electricity needs of its customers and all load in an RTO pays the market price for energy, the selection of generation technology to meet its capacity obligations can earn revenues in the RTO energy market that will financially hedge the cost of serving load. Furthermore, as discussed in the Companies' RTO study, NGCC technology was selected by the Companies' consultant as part of the Companies' generation resources to replace retiring coal units if they were to join PJM.

a. No other PPL regulated affiliates own or control generation. One affiliate is a member of PJM and the other is a member of ISO-NE. Both Pennsylvania and Rhode Island are retail access states, so the Companies' regulated affiliates in those states only have provider of last resort obligations and no responsibility for capacity or generation reliability.

b. They do not. See the response to part (a).

c. See the response to part (b).

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Question No. 31

Responding Witness: Lonnie E. Bellar / Robert M. Conroy / Tim A. Jones

Q-31. Refer to the Direct Testimony of Tim A. Jones (Jones Direct Testimony), page 8.

a. Identify and explain the provisions in the IRA that significantly accelerate energy efficiency (EE), growth in distributed generation, space heating electrification, and increased electric vehicle (EV) adoption.

b. Refer also to LG&E/KU's current Tariffs. Describe the process a residential customer who purchases an EV would go through to be able to charge the vehicle at the residence and the separate charges that the residential customer would incur to have the EV charger installed and how the customer would be billed.

c. Refer also to LG&E/KU's current Tariffs for Residential Time-of-Day Energy Service.[29] In addition to the incentives included in the IRA and LG&E/KU's deployment of AMI meters, explain why the 500-customer limit on customers taking Residential Time-of-Day Energy Service should not be increased or removed.

d. Explain whether LG&E/KU have received indication from the new Blue Oval battery plant of a preference for a proportion of its energy requirements to be satisfied by renewable energy.

A-31.

a. The Inflation Reduction Act ("IRA") provides financial incentives for energy efficiency, growth in distributed generation, space heating electrification, and increased electric vehicle adoption. The Companies summarize below the

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[29] LG&E's Electric Tariff, P.S.C. Electric No. 13, Second Revisions of Original Sheet No. 6 (effective Dec. 6, 2021); KU's Tariff, P.S.C. Electric No. 13, Second Revisions of Original Sheet No. 6 (effective Dec. 6, 2021).

provisions they have identified as pertinent for consideration in load forecasting:[30]

$7,500 tax credit for new electric vehicles

- Extends existing tax credit through 2032.
- There are income limits and vehicle qualifications.

$4,000 for used electric vehicles

- Tax credit ($4,000 or 30% of the sale price, whichever is less) is for used versions of clean vehicles.
- There are income limits and vehicle qualifications.

30% tax credit for solar panels, wind energy, battery storage

- Residential Clean Energy Credit: costs from beginning of 2022 to end of 2032 qualify for a 30% tax credit. The credit is 26% in 2033 and 22% in 2034.
- Under pre-IRA law, individuals would receive a 22% credit in 2023 (instead of 30% under the IRA). The credit would have ceased entirely beginning in 2024 absent the IRA.
- The tax credit for battery storage technology is extended for expenditures made starting in 2023 and now also includes stand-alone battery storage.

Up to $3,200 a year for home efficiency projects

- 30% "Energy Efficient Home Improvement Tax Credit " for installing efficient exterior windows, skylights, and other items. Homeowners get up to $1,200 a year, with a larger $2,000 total annual credit applied to certain projects (further described below).
- The credit is offered through 2032 and applies during the year a project (which must meet certain efficiency criteria) is installed.
- Annual caps apply to certain items (e.g., windows). Up to $2,000 annually is available for installations of certain electric or natural gas heat pumps, electric or natural gas water heaters, and biomass stoves or boilers.
- The credit for a home energy audit rises to $150 and an electrical panel upgrade rises to $600.

New Energy Efficient Homes Credit

- Extends through 2032 an existing credit that previously expired at the end of 2021.

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[30] For a full discussion of the IRA, see "Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action," available at: https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf.

- $2,500 for new homes meeting Energy Star standards; $5,000 for certified zero-energy ready homes. For multifamily, base amounts are $500 per unit for Energy Star and $1000 per unit for zero-energy ready.

Grants for efficiency and electrification
Two grant programs ($8.8 billion total) will be run by state energy offices using guidelines from the U.S. Department of Energy ("DOE").

- $4.3 billion will go to the HOMES (Home Owner Managing Energy Savings) rebate program to incentivize retrofits.
    - Rebates for 50% of the retrofit's cost up to a dollar-value cap.
    - Energy reduction of 20% for an entire home gets maximum rebate of $2,000 or half the cost of the retrofit project, whichever is less. The rebate cap is $4,000 for those who reduce energy at least 35%. The rebates double ($4,000 and $8,000, respectively) for lower-income households. A multifamily building could get $400,000. Income must be 80% or less of an area's median income to qualify.
- $4.5 billion will go to the High-Efficiency Electric Home Rebate Program to incentivize home electrification.
    - As much as $14,000 to homeowners for:
        - Appliance purchases—up to $1,750 for a heat pump water heater; $8,000 for a heat pump for space heating or cooling; and $840 for an electric stove or an electric heat pump clothes dryer.
        - Non-appliance upgrades—$4,000 for an electric load service center (i.e., main panel) upgrade; $1,600 for insulation, air sealing and ventilation; and $2,500 for electric wiring.
    - Income limits:
        - Rebates not for households earning >150% of the area's median income.
        - Those with income below 80% of the area median get rebate for full cost of upgrades ($14,000 cap).
        - Those between 80% and 150% of the area median income get rebates of 50% of cost (up to $14,000).

Commercial Buildings Energy Efficiency Credit

- The Commercial Buildings Energy Efficiency credit is expanded: $2.50 to $5.00 per square foot for businesses with 25-50 percent reductions in energy use over existing building performance standards.

Zero Building Energy Adoption Code

- $1 billion to the DOE to provide technical assistance to states and municipalities to assist with zero-emission buildings. Local governments with building code authority are eligible.
- $330 million to the DOE to help states and local governments adopt codes that meet or exceed the 2021 International Energy Conservation Code (for residential) or the ANSI/ASHRAE/IES Standard 90.1-2019 (for commercial).
- $670 million (available until September 2029) for adoption of codes that meet or exceed "the zero energy provisions in the 2021 International Energy Conservation Code or an equivalent stretch code" and for related compliance plans.

Environmental and Climate Justice Block Grants

- $3 billion in block grants to fund environmental justice projects for disadvantaged communities.
- Eligible projects address environmental harms in low-income and disadvantaged communities through investment in, among other things, low- and zero-emission infrastructure.

b. The Companies do not have any tariffs related to the installation of EV chargers at a customer's residence. A residential customer would need to contract with a third-party electrician for installation of EV charging equipment. A residential customer with an EV charger would continue to be served on one of the Companies' residential tariffed rates (RS, RTOD-E, or RTOD-D).

c. The Residential Time-of-Day Energy Service rate design is based on an analysis utilizing a statistical sample to forecast the hourly load for the entire residential rate class. The 500-customer limit on this rate was set to limit any revenue recovery risk caused by potential sampling error. The Companies are in the early stages of AMI deployment. As the Companies continue to receive hourly load data on all its residential customers, an analysis of the load data will be utilized to evaluate the current rate design. In addition, the pricing structure of the RTOD-E rates will also be reevaluated as the underlying energy cost differences between on-peak and off-peak hours are not tied to the underlying energy cost. The rate difference was designed to incentivize customers to alter their usage patterns, but the on-peak and off-peak rates differ far more than the underlying costs would justify. Should the customer limit of these rate schedules be removed, these cost differences between the two time periods will need to be reviewed to mitigate revenue recovery risks. Based on the outcome of this analysis the Company will evaluate increasing or eliminating the customer limit within its next general rate case.

d. Blue Oval has indicated an interest in having up to 300 MW of solar generation. KU and Blue Oval are in discussions surrounding the timing, size, and source of up to 300 MW of renewable energy. Upon a final agreement, KU will file a separate renewable special contract and seek Commission approval.

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Question No. 32

Responding Witness: Tim A. Jones

Q-32. Refer to the Jones Direct Testimony, page 9, Figure 3. Explain what the solid line in each panel represents.

A-32. See footnote 6 on page 8 of Exhibit TAJ-1. The line is a smoothed trend-line through the daily minimum load values. The purpose of showing the smoothed minimum trend-line is to demonstrate that the Companies' customers consistently demand significant amounts of energy at all times, not just during peak hours.

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Question No. 33

Responding Witness: Lana Isaacson / Tim A. Jones / Stuart A. Wilson

Q-33. Refer to the Jones Direct Testimony, page 16, lines 12–14 and page 29, lines 1–10.

a. Explain whether LG&E/KU included the resulting bill impacts of the projects proposed in this case when forecasting savings from anticipated residential and commercial adoption of DSM and EE programs. If so, explain specifically how the costs were included in the bills for each customer class.

b. Explain why it is reasonable to assume LG&E/KU ratepayers will experience price increases of 2 percent annually consistent with long-term inflation as opposed to projected price increases resulting from fuel price increase plus rate increases resulting from the LG&E/KU's future actions.

A-33.

a. No, the Companies did not directly, explicitly model bill impacts on DSM-EE program adoption for any of the portfolios analyzed. Consistency and analytical accuracy would require evaluating the bill impacts on DSM-EE adoption of *all* portfolios evaluated, not only the proposed portfolio.

But more importantly, the results of accounting for such impacts, if any, should have no effect on the optimal resource portfolio for meeting minimum reserve margins. As shown in Exhibit SAW-1, PLEXOS did not select dispatchable DSM as an economical resource for meeting minimum reserve margins in any fuel price scenario even though the model could have chosen any of the dispatchable DSM programs listed in Table 44 of Exhibit SAW-1 at any time and in any combination. Indeed, not only did PLEXOS not select any new dispatchable DSM programs, it chose to retire the existing programs to minimize the present value of revenue requirements while meeting minimum reserve margin requirements.[30]

[30] *See, e.g.,* Exhibit SAW-1 at 30.

Regarding non-dispatchable DSM-EE programs, the Companies' load forecast already assumes a substantial amount of energy efficiency to account for the proposed DSM-EE Program Plan and the effects of the Inflation Reduction Act. The Companies' assumed energy-efficiency savings are already near or at the upper bounds of reasonableness given existing technology and economics. Therefore, it is improbable that any marginal effect on DSM-EE adoption associated with bill impacts resulting from the optimal or any other portfolio the Companies evaluated would in turn affect the makeup of the optimal portfolio.

b. Future fuel prices, utility investments, interest rates, and other factors that can affect customers' energy costs are uncertain. For example, natural gas spot prices at Henry Hub in February 2023 fell to less than $2.50/MMBtu from recent highs of more than $9.00/MMBtu in summer 2022.[31] Moreover, because electricity consumption is largely price inelastic, deviations from a 2% annual growth rate would not materially impact the load forecast.[32] Therefore, estimating customers' long-term energy cost growth at 2% per year is reasonable for load forecasting purposes.

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[31] *See, e.g.,* EIA's Henry Hub Natural Gas Spot Price page, available at: https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm.
[32] *See, e.g.,* Jones Direct Testimony at 29:1–10.

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Question No. 34

Responding Witness: Tim A. Jones

Q-34. Refer to the Jones Direct Testimony, page 16, lines 8–11, which provides "the IRA incentivizes energy efficient or electric end-use appliances (not just heat pumps) by providing qualifying low- and mid-income customers home efficiency and electrification tax incentives and rebates up to a lifetime maximum of $14,000."

a. Confirm that this refers to High-Efficiency Electric Home Rebate Act (HEERHA) program rebates for home electrification and weatherization included in the IRA and is described as one of the two impacts that the IRA has that tends to reduce the load forecast.

b. Explain whether LG&E/KU's modeling incorporated other IRA energy efficiency provisions in the load forecast, and if so, how. Specifically, explain whether the Residential Energy Efficiency Tax Credit, which provides up to $3,200 per year in tax credits for all income classes, was incorporated into modeling.

A-34.

a. See the response to Question No. 31(a). The two IRA impacts that tend to reduce the load forecast are, generally, (1) incentives for distributed generation and (2) incentives for more efficient appliances. HEERHA is an example of an IRA program that provides both incentives for more efficient appliances as well as incentives for electrification. Incentives in the HEERHA for home electrification would tend to increase the electric load forecast.

b. As discussed in the second paragraph on page 20 of Exhibit TAJ-1, the Companies modeled the effects of the proposed non-dispatchable DSM-EE programs and all IRA programs that tend to reduce load together. Because details regarding the implementation of various IRA programs are still relatively unknown, this is a reasonable approach.

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Question No. 35

Responding Witness: Tim A. Jones

Q-35. Refer to the Jones Direct Testimony, page 16. Refer also to the Commission Staff's Report in LG&E/KU's 2021 IRP in Case No. 2021-00393 stating that LG&E/KU should "expand its discussion of [distributed energy resources (DERs)] 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."[4] Refer also to the Jones Direct Testimony, page 21, in which Jones explains that in LG&E/KU's 2022 CPCN Load Forecast, LG&E/KU only analyze distributed solar generation, noting that "if future DER customers choose their DER technology on the basis of economics, they will almost certainly choose solar over wind, hydro, biomass, and battery energy storage."

a. Indicate whether policy changes, decreasing costs, or changing markets were considered in the economics and uptake of home battery storage.

b. Indicate if aspects other than economics for home battery storage, such as resiliency benefits and the increasing value it may provide, were considered in customer adoption of the technology.

A-35.

a. No, but absent significant policy or technological changes, home battery storage systems are unlikely to become economical in the Companies' service territories in the near term. As discussed in Section 3.6.1.5 on page 25 of Exhibit TAJ-1, such systems appear not to be economical even in southern California, which has energy rate levels much more likely to create beneficial home battery storage economics, as well as higher solar irradiance to support solar paired with energy storage.

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[4] Case No. 2021-00393, Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (Ky. PSC Sept. 16, 2022), Commission Staff's Report on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company at pg. 67.

This is even truer for the Companies' customers. For example, KU's average residential NMS-2 customer today consumes nearly 15,000 kWh per year from KU and exports around 6,000 kWh to KU per year.[33] Assuming an average all-in energy charge for the Companies under Rate RS of about $0.12/kWh (including all cost-recovery mechanisms) and a blended NMS-2 compensation rate of $0.07/kWh, even if a customer had a highly efficient battery system, such as a Tesla Powerwall, which claims a 90% roundtrip efficiency, an NMS-2 customer with a consumption and export profile like the current average KU NMS-2 customer would achieve net savings of only $270 per year by storing and later using excess production rather than receiving NMS-2 bill credits for it. Continuing with the Tesla Powerwall example, that level of net bill savings would require 43 years to cover the current $11,500 cost of a single 13.5 kWh Powerwall unit.[34] Assuming a 30% tax credit associated with the battery results in a net price of $8,050 (excluding any applicable sales taxes), which reduces the payback period from 43 years to 30 years—still 20 years longer than the 10-year warranty period.[35] Battery costs would have to decline to less than $4,000 (from their current $11,500) and maintain the 30% tax credit for NMS-2 customers to reasonably expect to break even on such a system on extremely favorable assumptions within a 10-year battery warranty period.[36]

Consider also a KU RTOD-Energy customer as an example, who has a significantly higher on-peak to off-peak energy rate difference (about $0.15/kWh) than an LG&E RTOD-Energy customer (about $0.10/kWh).[37] The average KU residential customer uses approximately 21% of their annual consumption, or about 2,900 kWh, during on-peak hours per year. Again, assuming a 90% roundtrip efficiency, the average KU residential customer could obtain bill savings of $391 per year by charging the battery with off-peak energy sufficient to meet all of the customer's on-peak energy requirements, assuming that is feasible. With those assumptions, it would take over 20 years for such a customer to break even on a $11,500 Tesla Powerwall with the 30% tax credit (nearly 30 years without the tax credit), which is well in excess of the battery's 10-year warranty. Thus, battery costs would essentially need to be cut in half and maintain the 30% tax credit for RTOD-Energy customers to reasonably expect to break even on such a system on extremely favorable assumptions within a 10-year battery warranty period.[38]

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[33] The Companies used a KU customer as the example case because the economics become more unfavorable for customers with gas heating, which is common in the LG&E service territory.
[34] *See* https://www.forbes.com/home-improvement/solar/tesla-powerwall-solar-battery-review/ (accessed Feb. 20, 2023).
[35] *Id.*
[36] *Id.*
[37] *See* Kentucky Utilities Company, P.S.C. No. 20, Second Revision of Original Sheet No. 6; Louisville Gas and Electric Company, P.S.C. Electric No. 13, Second Revision of Original Sheet No. 6.
[38] *Id.*

But it is far from certain that battery storage prices, including the prices of home battery storage systems, will decrease so significantly, at least in the near term. For example, according to BloombergNEF, lithium-ion battery pack prices rose 7% in real terms in 2022 and are expected to remain at elevated levels in 2023, which is a marked change from the dramatic decreases in such prices from 2013 through 2021.[39] Bloomberg NEF further stated that its "2022 Battery Price Survey predicts that average pack prices should fall below $100/kWh by 2026 [about a third below current prices]. This is two years later than previously expected …."[40] For reference, BloombergNEF data indicates lithium-ion battery pack prices fell dramatically (about 73%) from 2013 ($732/kWh) to 2018 ($198/kWh), but they decreased much more gradually from 2018 to 2021 ($141/kWh) before rebounding to $151/kWh in 2022 (a 24% reduction since 2018).[41] This suggests that BloombergNEF's projected price reduction of more than 33% from expected 2023 levels (about $150/kWh) by 2026 (less than $100/kWh) is uncertain at best.[42]

b. No. It is unclear what is intended by "the increasing value it may provide" in the data request; the economics of residential battery storage systems are addressed in response to part a. above. Regarding resiliency, a backup home generator would be a far more economical option than battery backup for obtaining superior resiliency. For example, a 14kW natural gas or LP-fueled standby generator that can run continuously for twenty-four hours or more is available at retail for less than $5,000.[43] A Powerwall with 5.8 kW continuous and 10 kW peak output—and only 13.5 kWh storage capacity—costs $11,500.[44]

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[39] *See* BloombergNEF, "Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh," Dec. 6, 2022, available at https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/ (accessed Feb. 20, 2023).
[40] *Id.*
[41] *Id.*
[42] *Id.*
[43] *See, e.g.,* https://www.lowes.com/pd/Generac-Guardian-14kW-Home-Backup-Generator-with-16-circuit-Transfer-Switch-WiFi-Enabled/5001372697.
[44] https://www.forbes.com/home-improvement/solar/tesla-powerwall-solar-battery-review/.

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Question No. 36

Responding Witness: Tim A. Jones

Q-36. Refer to the Jones Direct Testimony, page 17, lines 17–22, and page 18, lines 1–4. Explain in further detail the reasonableness of accelerating the IRA impacts on the Energy Information Administration (EIA) forecast by ten years. Include in the response the characteristics of LG&E/KU's service territories that would warrant assuming swifter adoption impact results.

A-36. See the discussion on page 20 of Exhibit TAJ-1. The Companies modeled the impact over 10 years because the IRA's pertinent incentives and programs are roughly 10 years in duration. The proposed DSM-EE programs go through 2030. The extent to which these IRA and DSM-EE programs will accelerate efficiency improvements is uncertain. As shown in Figure 9 on page 18 of the Jones Direct Testimony, the Companies modeled a 10-year acceleration and demonstrated that a 15-year acceleration would produce similar results due to fact that EIA efficiency projections begin to plateau in 10 years. The Companies are not aware of characteristics in their service territories that would warrant assuming swifter adoption (i.e., a 15-year acceleration versus a 10-year acceleration), but this assumption would not materially impact the load forecast.

The key in modeling impacts is accounting for differences in end-uses between LG&E and KU service territories. For example, LG&E currently has a higher saturation of gas heating, so the modeled impact of home electrification incentives is greater in the LG&E service territory. See the Jones Direct Testimony and Exhibit TAJ-1 for a full discussion.

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Question No. 37

Responding Witness: Robert M. Conroy / Tim A. Jones

Q-37. Refer to the Jones Direct Testimony, page 23, lines 4–15. Assume that LG&E/KU receive approval for the planned fossil and renewable generation additions as proposed.

a. Explain why it would not be reasonable for LG&E/KU to remove the 1 percent cap on distributed generation eligible for the Net Metering Service 2 (NMS-2) compensation rate.

b. Explain whether the Small Capacity Cogeneration Qualifying Facilities (SQF) tariff rate paid to net metering customers was held at the current tariffed rate or recalculated to reflect the cost of new generation. If held at the current rate, explain why that is a reasonable assumption.

A-37.

a. The Companies' current tariffs do not have a 1% cap on distributed generation eligible for service under Rider NMS-2.[45] Note that the Companies' modeling does not assume that they will cease to offer net metering to new customer-generators per se upon reaching the 1% threshold; rather, it effectively assumes the compensation paid to all new distributed generation customers with facility capacities equal to or less than 45 kW will be at small qualifying facility ("SQF") rates irrespective of whether such customers are net metering or SQF customers. It is reasonable to assume for load forecasting purposes that the Companies' customers would pay no more than legally required for energy, and the Companies project that distributed generation will continue to grow with energy exports compensated at SQF rates.

b. The SQF tariff rate assumed to be paid to all new distributed generation customers with facility capacities equal to or less than 45 kW after reaching

[45] *See* Kentucky Utilities Company, P.S.C. No. 20, First Revision of Original Sheet No. 58; Louisville Gas and Electric Company, P.S.C. No. 13, First Revision of Original Sheet No. 58.

the 1% threshold started at the current rate and then was escalated two percent annually consistent with the assumed long-term rate of inflation.[46]

Question No. 38

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-38. Refer to the Jones Direct Testimony, Exhibit TAJ-1, page 15. Explain whether Blue Oval will take part in or has expressed an interest in an interruptible tariff as a part of its service.

A-38. BlueOval has not expressed interest in interruptible service.

[46] See Exhibit TAJ-1 at 29-30.

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Question No. 39

Responding Witness: Tim A. Jones

Q-39. Refer to the Jones Direct Testimony, Exhibit TAJ-1, page 16. Provide a list of the energy efficiency incentives available to homeowners from the IRA.

A-39. See the response to Question No. 31(a), which describes the Energy Efficient Home Improvement Tax Credit, Home Owner Managing Energy Savings (HOMES) Rebate, New Energy Efficient Homes Credit, and High-Efficiency Electric Home Rebate.

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Question No. 40

Responding Witness: Robert M. Conroy / Tim A. Jones

Q-40. Refer to the Jones Direct Testimony, Exhibit TAJ-1, page 19.

a. Explain what rate schedule LG&E/KU assumes for the EV load shapes.

b. If known, explain what the load shape would look like and how charging behavior would change if EV owners were on Tariff RTOD-Energy or Tariff RTOD-Demand. Include in the response whether residential customers must take both of these tariffs jointly or individually.

A-40.

a. See Figure 18 on page 19 of Exhibit TAJ-1 as a proxy for the EV charging profile. The EV load shape is not developed as a function of a particular rate schedule. Consistent with the proposed Managed EV Charging DSM Program, the majority of EV charging is assumed to occur from home in the overnight hours so that EV charging has a minimal impact on the Companies' peak demands.

b. Based upon current tariff language, a customer must take service on one RTOD rate schedule or the other but cannot take service under both RTOD Energy and RTOD Demand simultaneously. The assumption of overnight charging in non-peak hours is consistent with what would be expected for EV owners on these tariffs.

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Question No. 41

Responding Witness: Philip A. Imber

Q-41. Refer to the Wilson Direct Testimony, page 4, lines 4–13, generally discussing the effect and requirements of the Good Neighbor Plan. Refer also to the Imber Direct Testimony, page 5, lines 11–13, discussing when LG&E/KU expect the Good Neighbor Plan to become effective. Because the Good Neighbor Plan has such far consequences, explain whether LG&E/KU know or believe that lawsuits seeking revisions or to delay implementation have been filed or will be filed.

A-41. The Good Neighbor Plan, a Cross State Air Pollution Rule, is not final. The EPA has clear authority and obligation to implement a Cross State Air Pollution Rule. When enacted by EPA, the requirements of the Good Neighbor Plan will be effective. Compliance will be required. The Companies have no sound basis to expect any potential litigation will successfully delay the implementation of the Good Neighbor Plan. The contention that litigation will likely cause the delay implementing Good Neighbor Plan is speculative and an imprudent assumption for purposes of complying with the law and providing reliable least-cost service to customers. For the reasons discussed in Mr. Bellar's testimony, the time to act is now.

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Question No. 42

Responding Witness: Stuart A. Wilson

Q-42. Refer to the Wilson Direct Testimony, page 4, lines 4–13, generally discussing the effect and requirements of the Good Neighbor Plan. If LG&E/KU were to make the investments in selective catalytic reduction (SCR) technology, explain how much longer each of the units could run and whether that would obviate the need for the two proposed NGCC units.

A-42. Notwithstanding costs to customers, if the Companies were to make the investments in SCR technology, it would eliminate the immediate need for the two proposed NGCC units assuming Brown 3 continues to operate, but it is unclear how much longer each of the units could run given their age and the uncertainty regarding future environmental regulations. See discussion in Section 4.5 of Exhibit SAW-1 regarding Portfolio 5 where SCR is added to Mill Creek 2 and Ghent 2, Brown 3 is overhauled in 2028, and the three coal units are assumed to operate beyond 2050. Compared to the recommended portfolio (Portfolio 1), the PVRR for Portfolio 5 is $583 million higher assuming no future CO_2 prices and $1.8 to $2.6 billion higher with CO_2 prices.[47]

[47] These values are taken from Table 13 on page 32 of Exhibit SAW-1 assuming Mid gas, Mid CTG fuel prices. Portfolio 5 is higher cost than Portfolio 1 in all fuel and CO_2 price scenarios.

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Question No. 43

Responding Witness: Stuart A. Wilson

Q-43. Refer to the Wilson Direct Testimony, page 3, lines 3–14. For each proposed unit addition or retirement, provide the installed capacity (ICAP) and unforced capacity (UCAP) ratings for both summer and winter, and explain which capacity value is utilized in the PLEXOS production cost model and how.

A-43. The Companies are not in an RTO, so they do not routinely utilize the terms ICAP and UCAP. However, applying these concepts to the Companies' generation fleet, the table below shows ICAP as the installed net capacity in both the summer and winter for each of the thermal units and UCAP as the ICAP less the assumed unplanned outage rates for each of the thermal units. For the solar and BESS resources, the ICAP is shown as the nameplate AC rating but no UCAP is shown because the Companies did not assume unplanned outage rates for these resources.

MW	**ICAP**			**UCAP**	
	Summer Net	**Winter Net**	**Solar/BESS AC Nameplate**	**Summer Net**	**Winter Net**
Mill Creek 2	297	297	NA	281	281
Brown 3	412	416	NA	374	377
Ghent 2	485	486	NA	458	459
Mill Creek NGCC	621	641	NA	580	599
Brown NGCC	621	641	NA	580	599
Marion County Solar	NA	NA	120	NA	NA
Mercer County Solar	NA	NA	120	NA	NA
Song Sparrow Solar PPA	NA	NA	104	NA	NA
Gage Solar PPA	NA	NA	115	NA	NA
Nacke Pike Solar PPA	NA	NA	280	NA	NA
Grays Branch PPA	NA	NA	138	NA	NA
Brown BESS	NA	NA	125	NA	NA

The Companies used several capacity definitions in PLEXOS modeling for different purposes.

- For the thermal units, the average of summer and winter ICAP was used as the basis for fixed cost calculations such as stay-open costs and capital costs and recovery. The seasonal ICAP figures were used for calculating total capacity reserves in both summer and winter.
- For the units being proposed for retirement (Mill Creek 2, Brown 3, and Ghent 2), the seasonal ICAP figures were also used as seasonal ratings for economic dispatch. These units were modeled with unplanned outage rates and planned maintenance schedules separate from the ratings, so no UCAP was used in PLEXOS.
- For the proposed new thermal units (Mill Creek NGCC and Brown NGCC), the Companies modeled the potential to build future NGCC units identical to the proposed new units if economic. To simplify the modeling, the UCAP figures were used as the seasonal ratings for economic dispatch in months outside the typical planned outage season.[48] In months during the typical outage season, the seasonal ratings used for economic dispatch reflected their UCAP plus an assumed planned outage rate,[49] resulting in an adjusted UCAP of 435-449 MW.
- For the solar PPAs, the ICAP figures were multiplied by solar's seasonal capacity credits to calculate seasonal firm capacity as a PLEXOS input for calculating total capacity reserves in both summer and winter.
- The Marion and Mercer solar facilities and the Brown BESS were not modeled in PLEXOS.[50]

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[48] Typical outage season months comprise March, April, October, and November.
[49] The planned outage rate assumes 4 weeks per year of planned outages per unit.
[50] *See* Exhibit SAW-1 at 12 ("The Companies excluded proposals for the purchase or development of solar and battery storage assets from advancing to the modeling analysis due to the economics of the proposals. The Companies revisited these proposals in Stage Three of the analysis described below.").

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Question No. 44

Responding Witness: Lonnie E. Bellar / Stuart A. Wilson

Q-44. Refer to the Wilson Direct Testimony, page 4, lines 13–18 and lines 19–23, and Exhibit SAW-1, Appendix B, page 4.

a. Explain each component of the major overhaul of the Brown Unit 3 that LG&E/KU contend is necessary to keep it operating safely beyond 2028.

b. Provide any cost benefit studies, along with a discussion of the assumptions used in the studies, used to justify the retirement of Mill Creek Unit 2, Brown Unit 3 and Ghent Unit 2.

A-44.

a. The primary scope of the Brown Unit 3 major outage consists of the disassembly, inspection, and repair or replacement of critical components associated with the high pressure, intermediate pressure, and low-pressure turbines. The inspection and repair also extend to the generator and auxiliary equipment, including, but not limited to turbine control valves, excitation system, lube oil pumps, coolers, and motors. The major turbine overhaul frequency is based upon OEM established intervals which factor starts/shutdowns and total operating hours. Associated with the standard turbine outage, are the replacement of the HP-IP Seals, HP Inlet Seals, and Turbine Blading.

During a major outage, boiler tubing sections are replaced based on life cycle management and previous inspection history. This overhaul would consist of the replacement of the economizer, lower water-wall slope, and reheat outlet dissimilar metal welds.

Additional pulverizer and absorber scopes are performed to maintain reliability. This overhaul includes a pulverizer dynamic classifier replacement, pulverizer gearbox overhaul, and an absorber inlet expansion joints replacement.

b. Exhibit SAW-1 is a summary of the analysis that demonstrates that the retirements of Mill Creek Unit 2, Brown Unit 3, and Ghent Unit 2 are least cost. A discussion of assumptions used in this study is provided throughout Exhibit SAW-1.

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Question No. 45

Responding Witness: Stuart A. Wilson

Q-45. Refer to the Wilson Direct Testimony, page 8, lines 4–6. Provide and explain the report and bid evaluation sheets that resulted in the 43 supply-side options and all dispatchable DSM options that were included in the resource analysis.

A-45. For a description of the screening process that resulted in selecting the 43 supply-side options, see Exhibit SAW-1, page 12. See the support file in Exhibit SAW-2 at \01_Screening\ CONFIDENTIAL_20221212_2022RFP_PLEXOS_Screening_Inputs_0308.xlsx. Because all dispatchable DSM options were included for further evaluation, no screening was performed.

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Question No. 46

Responding Witness: Stuart A. Wilson

Q-46. Refer to the Wilson Direct Testimony, page 8, lines 7–12. Explain whether the six fuel price scenarios used in Stage 1 are the same fuel price scenarios used in Stage 2.

A-46. Yes, the six fuel price scenarios used in Stage 1 are the same fuel price scenarios used in Stage 2.

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Question No. 47

Responding Witness: Christopher M. Garrett / Stuart A. Wilson

Q-47. Refer to the Wilson Direct Testimony, page 10–11.

a. Explain whether LG&E/KU's project engineering group updated their solar and storage, SCCT, and NGCC proposals to account for the IRA.

b. If yes, explain in detail what changes the updated proposals included.

A-47.

a. The Companies' Project Engineering group provided the estimated costs to build and operate each of their RFP responses. The tax implications of their proposals were addressed in the Resource Assessment prepared by Generation Planning. Therefore, no updates were needed from Project Engineering.

To evaluate the two owned solar proposals, the Companies assumed a $27.50/MWh production tax credit ("PTC") for the first 10 years of each project's operating life. To evaluate the Brown BESS proposal, the Companies assumed a 50% investment tax credit ("ITC").[51] Since the case was filed, the Companies have further reviewed the accounting treatment for these tax credits and determined that there will be additional reductions to customer revenue requirements.

Regarding the PTC, the Companies determined that the PTC for the owned solar projects should be grossed up for taxes to fully reflect its impact on revenue requirements. As a result of this change, revenue requirements over the first ten years of the solar projects' life will be reduced by an additional $9.14/MWh (see table below). This change improves the PVRR of the proposed solar assets by $27.7 million.[52]

[51] See section 7.5 of Exhibit SAW-1.
[52] Revenue requirements are approximately $4.8 million per year lower for 10 years ($4.8 million = 240 MW * 25% capacity factor * 8,760 hours/year * $9.14/MWh).

Solar PTC: Revenue Requirement Impact ($/MWh)

Impact of PTC on Revenue Requirements in Exhibit SAW-1 ($/MWh)	(27.50)	
Tax Gross-up Factor	1.33	1 / (1-24.95%)
Updated Impact of PTC on Revenue Requirements ($/MWh)	(36.64)	
Change ($/MWh)	(9.14)	

Regarding the ITC, the Companies determined that revenue requirements should include the impact of a 50% basis reduction associated with the ITC and that the net tax benefit should be grossed up for taxes to fully reflect its impact on revenue requirements (see table below). With these changes, the nominal impact of the tax benefit on revenue requirements increases from $135 million to $157 million.

Brown BESS ITC ($ millions)		
Brown BESS Cost	$270	
ITC Reduction to Rev. Req. in Exhibit SAW-1	(135)	Cost $270 x 50%
ITC 50% Tax Basis Reduction	17	ITC $135 x 50% x 24.95%
Net Tax Benefit	(118)	
Tax Gross-up Factor	1.33	1 / (1-24.95%)
Updated Reduction to Rev. Req.	(157)	
Change	(22)	

Finally, the Companies completed their analysis of the Brown BESS before they determined it should be 100% owned by LG&E,[53] and the Companies are now assuming they will elect to opt out of the normalization requirements with respect to the BESS.[54] Accounting for the basis reduction, gross-up on ITC, LG&E ownership, and normalization opt-out improves the PVRR of the Brown BESS by $75.8 million.

These changes impact values in Tables 17, 18, 20, 21, and 22 in Section 4.6 of Exhibit SAW-1 as well as three workpapers in Exhibit SAW-2. Updated versions of these files are attached to this response and updated values are highlighted in orange. Certain information in the updated Exhibit SAW-1 and the entirety of the information in the updated workpapers is confidential and

[53] The analysis of Brown BESS in Exhibit SAW-1 (Section 4.6.2) assumed a generic 65% KU / 35% LG&E ownership share based on each company's share of total energy requirements.
[54] The IRA provides an election out of ITC normalization requirements for battery storage facilities pursuant to IRC section 50(d)2, provided such election isn't prohibited by any state or regulatory authority. This election could allow utilities to provide all benefits of ITC to ratepayers.

proprietary and is being provided under seal pursuant to a petition for confidential protection.

The IRA does not impact SCCT and NGCC proposals.

b. Not applicable.

The attachment is being provided in a separate file.

The entire attachment is confidential and provided separately under seal.

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Question No. 48

Responding Witness: Christopher M. Garrett / Stuart A. Wilson

Q-48. Refer to the Wilson Direct Testimony, page 14–15.

a. Explain whether the coal units are dispatched economically or committed as "must run resources."

b. Explain whether coal retirement was endogenously selected in the model or whether different retirement dates were investigated through scenario analysis. In any case, identify the earliest and latest retirement dates examined and any other model constraints for the retirements of the units.

c. Provide a copy of any analysis of the book life or operating life of LG&E/KU's coal units prepared or relied on in the last seven years to establish depreciation rates or make resource decisions, and briefly explain how the conclusions of those analyses changed over time.

d. Provide the "Financial Model built in Excel to calculate and compare 17 PVRR values for various portfolios."

A-48.

a. With the exception of a 50 MW portion of the Companies' share of OVEC, to which the Companies are contractually obligated, all coal units are dispatched economically.

b. Retirement dates for Brown 3, Mill Creek 2, and Ghent 2 were allowed to be endogenously selected in PLEXOS throughout the modeled period, which covered the years 2027 through 2050.

c. The book lives were established as part of the depreciation studies completed by John J. Spanos in conjunction with internal analyses performed by the Companies. The depreciation studies were filed as part of the testimony of John J. Spanos in the last three rate case proceedings with links provided below. See attached the internal analyses performed by the Companies for the previous three depreciation studies. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The table shown below provides the retirement years for the various steam generating units from the previous three depreciation studies. The "Analysis of Generating Unit Retirement Years" dated October 2020 provides the basis for the change in retirement dates for the 2020 depreciation study. This was filed as Exhibit LEB-2 in the most recent rate cases as discussed in the testimony of Mr. Bellar. An update to this analysis was subsequently performed to reflect the changes resulting from the Good Neighbor Plan. This update is included as part of Exhibit SAW-1 and serves as the basis for the change in retirement dates recommended in this proceeding.

Note: Book depreciation rates impact the calculation of capital revenue requirements for existing resources but otherwise do not impact resource decisions (e.g., in the Companies' analysis, Brown 3, Mill Creek 2, and Ghent 2 could operate beyond the end of their book depreciation lives with the appropriate capital investments).

Louisville Gas and Electric Company

	Depreciation Study			Resource Assessment
Steam Unit	12/31/2015	12/31/2017	6/30/2020	Dec. 2022
Mill Creek Unit 1	2032	2032	2024	2024
Mill Creek Unit 2	2034	2034	2028	2027
Mill Creek Unit 3	2038	2038	2039	2039
Mill Creek Unit 4	2042	2042	2039	2039
Trimble County Unit 1	2050	2050	2045	2045
Trimble County Unit 2	2066	2066	2066	2066

Kentucky Utilities Company

	Depreciation Study			Resource Assessment
Steam Unit	12/31/2015	12/31/2017	6/30/2020	Dec. 2022
Brown Unit 3	2035	2035	2028	2028
Ghent Unit 1	2034	2034	2034	2034
Ghent Unit 2	2034	2034	2034	2028
Ghent Unit 3	2037	2037	2037	2037
Ghent Unit 4	2038	2038	2037	2037
Trimble County Unit 2	2066	2066	2066	2066

- KU 2015 depreciation study:

https://psc.ky.gov/pscecf/2016-00370/derek.rahn%40lge-ku.com/11232016073202/10_-_KU_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf

- KU 2017 depreciation study: https://psc.ky.gov/pscecf/2018-00294/derek.rahn%40lge-ku.com/09282018074941/11_-_KU_Testimony_and_Exhibits_2_of_3.pdf
- KU 2020 depreciation study: https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp%40lge-ku.com/11252020084757/12-KU_Testimony_3of4%28Spanos%29.pdf

- LG&E 2015 depreciation study: https://psc.ky.gov/pscecf/2016-00371/derek.rahn%40lge-ku.com/11232016075206/10_-_LGE_Testimony_and_Exhibits_-_Malloy_to_Spanos_-_FINAL.pdf
- LG&E 2017 depreciation study: https://psc.ky.gov/pscecf/2018-00295/derek.rahn%40lge-ku.com/09282018081716/11_-_LGE_Testimony_and_Exhibits_2_of_3.pdf
- LG&E 2020 depreciation study: https://psc.ky.gov/pscecf/2020-00350/rick.lovekamp%40lge-ku.com/11252020085918/12-LGE_Testimony_3of4%28Spanos%29.pdf

d. The Companies used different copies of the Financial Model for certain stages and steps of the analysis. The appropriate path and filenames are listed in the table below.[55]

Analysis Stage/Step	**Path/Filename in Exhibit SAW-2 Work Papers**
Stage One, Step Two	\04_FinancialModel\CONFIDENTIAL_20221209_FinancialModel_0308_Ph1_D01.xlsx
Stage Two	\04_FinancialModel\CONFIDENTIAL_20221209_FinancialModel_0308_Ph2_D01.xlsx
Stage Three, Steps One and Two	\04_FinancialModel\CONFIDENTIAL_20221209_FinancialModel_0308_Ph3_D01.xlsx

Please note that the Stage Three, Steps One and Two Financial Model was updated in the response to Question No. 47(a).

[55] Note that the quoted portion of the Wilson Direct Testimony at page 14, lines 16-17, does not include the numeral "17" in the text: "The Companies used a Financial Model built in Excel to calculate and compare PVRR values for various portfolios."

The attachment is being provided in a separate file.

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Question No. 49

Responding Witness: Stuart A. Wilson

Q-49. Refer to the Wilson Direct Testimony, page 14–15. Provide a list of all the Stage 1 runs with a brief description.

a. List all annual and cumulative resource limits of the model in each run (that restrict investment in a certain resource type).

b. List all resources that were forced in the model for each run.

A-49. See Section 4.4 in Exhibit SAW-1 for a detailed summary of the Stage One analysis. The Stage One analysis was completed in three steps. In the first step, the Companies used PLEXOS to develop and screen resource portfolios for the following six fuel price scenarios:

- Low Gas, Mid CTG Ratio
- Mid Gas, Mid CTG Ratio
- High Gas, Mid CTG Ratio
- Low Gas, High CTG Ratio
- High Gas, Low CTG Ratio
- High Gas, Current CTG Ratio

Table 5 on page 23 of Exhibit SAW-1 contains the results of these six model runs.

In the second step of the Stage One analysis, the Companies used PROSYM to develop detailed production costs for 22 portfolios over the six fuel price scenarios (a total of 132 runs). Table 7 on page 25 of Exhibit SAW-1 lists the 22 portfolios; Table 8 on page 25 of Exhibit SAW-1 contains the least-cost portfolio for each fuel price scenario.

In the third step of the Stage One analysis, the Companies used the results of the step two runs to determine how long Ghent 2 would have to operate to justify equipping it with an SCR in the single fuel price case in which it was least cost. No additional runs were developed for this step.

a. This subpart is applicable only to the PLEXOS model. The Companies did not impose any annual or cumulative resource limits that restricted investment in a certain resource type within PLEXOS.

b. This subpart is applicable only to the PLEXOS model. The Companies did not force any resources in PLEXOS. Section 4.4.1 on page 22 of Exhibit SAW-1 summarizes PLEXOS modeling assumptions.

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Question No. 50

Responding Witness: Stuart A. Wilson

Q-50. Refer to the Wilson Direct Testimony, page 16, lines 9–10.

a. Explain when the solar contracts were assumed to begin in the PLEXOS modeling and why this differed from the PROSYM modeling (RFP dates).

b. List all annual and cumulative resource limits of the model in each run (that restrict investment in a certain resource type).

c. List all resources that were forced in the model for each run.

A-50.

a. In Stage One, Step One, the solar contracts were allowed to begin in PLEXOS at any time after the beginning of the year closest to their proposed in-service dates. This assumption was made to allow PLEXOS to determine which proposals were economic at or near the beginning of their RFP-specified contract term. If PLEXOS was configured to add solar only on RFP-specified start dates, it would effectively screen portfolios with the assumption that solar can only be added in the first several years of the multi-decadal analysis period and likely overbuild solar resources during that period. All solar contracts selected by 2028 in the Stage One, Step One analysis were evaluated further in Stage One, Step Two. For Stage One, Step Two, the PROSYM modeling assumed solar projects would start on their RFP-specified start dates to reflect when the resources would actually be expected to be available.

b. See the response to Question No. 49, part (a).

c. See the response to Question No. 49, part (b).

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Question No. 51

Responding Witness: Stuart A. Wilson

Q-51. Refer to the Wilson Direct Testimony, page 10. Lines 7–12, Exhibit SAW-1, Appendix B, page 9, and Appendix D, Table 1, page 4. The capacity of the two proposed 621 MW NGCC units is greater than the proposed retired capacity of the three coal units 1,194 MW. Explain why the minimum reserve margin targets need to be greater than the capacity of the fully dispatchable resources of 12 percent summer and 21 percent winter.

A-51. Minimum reserve margin targets must be developed in way that is consistent with their application. Because the Companies have no plans to retire their existing intermittent and limited-duration resources, their minimum reserve margin targets of 17% in the summer and 24% in the winter were developed with the assumption that these resources would remain available and count towards reserve margin. Reserve margin targets of 12% in the summer and 21% in the winter are not consistent with this assumption. If the Companies did not have their existing intermittent and limited-duration resources, their reserve margin targets would be higher than 12% in the summer and 21% in the winter.

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Question No. 52

Responding Witness: Stuart A. Wilson

Q-52. Refer to the Wilson Direct Testimony, Exhibit SAW-1, page 5, stating that "[a]fter screening the RFP responses for economics and practicability, 43 options proceeded to the assessment."

a. Define "practicability" and explain how it was assessed.

b. Identify the resources that were excluded for practicability reasons.

c. Identify the resources that did not proceed to the assessment based on their economics.

d. For each resource that was considered and then excluded for practicability reasons, provide each basis for excluding each such resource.

e. Produce all workpapers for this screening step.

A-52.

a. Practicability in this context was the feasibility of a project being able to be realized or selected for further consideration compared to other alternatives. Pertinent factors included development risk, gas pipeline diversity considerations, RFP non-conformance, and rescinded proposals. The Companies also excluded proposals for asset ownership of solar and battery storage for the PLEXOS screening step.

b. For a list of the specific reasons that each excluded proposal that was not selected for screening in PLEXOS, see Column A on the tab "DataTable" in the file in Exhibit SAW-2 at \01_Screening\CONFIDENTIAL_20221212_2022RFP_PLEXOS_Screening_Inputs_0308.xlsx. The proposals that were not selected are categorized as follows:
- Pricing unfavorableness (48 proposals)
- Rescinded proposals (8 proposals)
- Solar/battery asset ownership (5 proposals)

- Pipeline diversity/multiple NGCC per site (3 proposals)
- Land acquisition risk (2 proposals)
- Non-conforming (1 proposal)

c. See the response to part (b).

d. See the response to part (b).

e. See the response to part (b).

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Question No. 53

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-53. Refer to the Wilson Direct Testimony, Exhibit SAW-1, page 5, subpart 3, and Table 1, page 11.

a. Explain how and whether the analysis of reliability enhancements was more qualitative in nature based on experience and personal knowledge or quantitative based on modeling results.

b. Explain how the cost of the Brown Energy Storage System (Brown BESS) compares to the costs of the 2-hour and 4-hour batteries submitted in response to the RFP.

c. Assuming that the Brown BESS will be utilized in the same manner as the combination solar/battery projects submitted in response to the RFP, explain how the cost of the Brown BESS utilized in conjunction with LG&E/KU's proposed solar projects compares to the combination battery/solar projects submitted in response to the RFP.

d. From a ratepayer's perspective, explain why it is more economical for LG&E/KU to own Brown BESS as opposed to accepting one of the RFP proposals.

e. Step 2 involved stress testing the economically optimal portfolio. Step 3 involved analyzing the addition of additional resources to the economically optimal portfolio. Explain and compare the portfolio cost differences between the economically optimal portfolio (Step 2) and the final portfolio (Step 3).

f. Provide a table showing the annual load forecast components and the annual existing resources, resource additions and retirements, net capacity position and reserve margin over the forecast period for both summer and winter seasons.

A-53.

a. The reliability analysis was quantitative based on modeling results. See section 4.6 of the Exhibit SAW-1 beginning on page 34. Please note that this section of Exhibit SAW-1 was updated in the response to Question No. 47(a).

b. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The attachment compares the cost of Brown BESS to the costs of the 2-hour and 4-hour battery proposals based on the projects' levelized costs. The cost of Brown BESS reflects the updates to ITC revenue requirement calculations discussed in the response to Question No. 47(a). The levelized cost of the other 4-hour battery proposals ranges from \$100,898/MW-Year to \$206,332/MW-Year and averages \$153,012/MW-Year. The levelized cost of the Brown BESS is \$138,133/MW-Year.

   In the Stage One, Step One analysis (Portfolio Development and Screening with PLEXOS), PLEXOS did not select battery storage as part of a least-cost portfolio in any of the fuel-price cases. Brown BESS is included to enhance reliability, but its primary value is in providing operational experience for integrating future renewable generation. It is not the most cost-effective means of enhancing reliability as modeled. See section 4.6.2 of the updated Exhibit SAW-1 beginning on page 36. See also the response to Question Nos. 25(b) and 25(c).

c. The Companies' BESS is not linked to, or limited to, the operation of solar. It will be connected to the transmission grid and will be directly charged with energy from the grid and will discharge energy into the grid independent of the operation of any solar projects on the system. See the response to part (b).

d. See Sinclair Direct Testimony at pages 25-26. The financial development and contractual risks of solar PPAs apply to BESS PPAs, and the industry's understanding of BESS as a means of improving reliability continues to develop. It is therefore unclear whether a BESS PPA would be more economical than the Brown BESS, but it would certainly involve additional risks and provide the Companies significantly less valuable operational experience with a technology that is likely to become increasingly important as renewable energy capacity grows.

e. Cost differences between the final portfolio (Step 3) and the economically optimal portfolio (Step 2) are due to the costs related to the Marion and Mercer solar assets and Brown BESS. The table below shows the incremental PVRR of each of these components in the fuel price scenarios with zero CO_2 price and zero REC price. As requested, the PVRR differences are computed with the assumption that the solar PPA projects in the economically optimal portfolio will be completed. These values reflect the updated PTC and ITC revenue requirement calculations described in the response to Question No. 47(a).

PVRR Comparison (Final Portfolio less Economically Optimal Portfolio, $M, 2022 dollars, Zero CO_2 Prices, Zero REC Prices*)

	Fuel Price Scenario (Gas, CTG Price Ratio)	PVRR Impact of Solar Assets	PVRR Impact of Brown BESS	Total PVRR Impact
Expected CTG	Low Gas, Mid CTG	253	130	384
	Mid Gas, Mid CTG	196	127	323
	High Gas, Mid CTG	35	95	131
Atypical CTG	Low Gas, High CTG	245	130	375
	High Gas, Low CTG	38	78	116
	High Gas, Curr CTG	-49	79	29

*Over the last three years, the Companies have sold Brown Solar RECs for between $8 and $13 per REC. A price of $10 per REC reduces the solar assets' PVRR impact by $72 million. Non-zero CO_2 prices would also improve the solar assets' economics.

f. See attached.

The entire attachment is confidential and provided separately under seal.

The attachment is being provided in a separate file.

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Question No. 54

Responding Witness: Charles R. Schram / Stuart A. Wilson

Q-54. Refer to the Wilson Direct Testimony, page 13, lines 17–20.

a. Explain how LG&E/KU modeled the uncertainty of solar PPA execution risk.

b. Explain whether any of the merchant solar projects that have already been issued Siting Board construction certificates submitted bids responding to LG&E/KU's Request for Proposal (RFP). If not, explain whether LG&E/KU considered approaching or approached one of these merchant projects as a possible resource.

c. Consider that with supply chain issues and long delays in RTO processing transmission interconnect study requests, several merchant solar projects have been or are expected to be canceled.

(1) Explain whether these specific considerations were discussed or taken into account in the solar project bidder's responses to LG&E/KU's RFP.

(2) Explain whether LG&E/KU have experienced or are aware of any delays in processing merchant renewable project interconnection requests to interconnect with its transmission system with its independent Transmission Organization, and if so, explain the timing and nature of the delays.

A-54.

a. The Companies evaluated the impact of the Mercer and Marion solar assets in a scenario where the contracted facilities for the four proposed PPAs as well as the Rhudes Creek and Ragland PPAs cannot be built. In this scenario, adding the solar assets is favorable in the majority of cases evaluated. See section 4.6.1 of Exhibit SAW-1 beginning on page 34. Please note that this section of Exhibit SAW-1 was updated in the response to Question No. 47(a).

b. The Companies are aware of one proposal submitted in response to the Companies 2022 RFP that has received Siting Board approval. That proposal was not pursued based on the project's price. The Companies did not approach the developers of projects that did not respond to the RFP.

c.

(1) With the exception of a wind proposal, projects submitted in response to the Companies' RFP were within the Companies' Balancing Authority ("BA") and therefore not subject to RTO approvals. Projects within the BA are also not subject to additional RTO transmission costs and the impacts of Locational Marginal Pricing ("LMP").

(2) Regarding the solar PPAs, neither the Grays Branch nor Nacke Pike projects have been submitted to the LG&E/KU Generator Interconnection queue. The ITO has completed the required studies for Song Sparrow. The ITO is processing earlier queued projects in the order they were received; as such, the estimated study start date for Gage has been delayed and is expected to begin on April 5, 2024.

The ITO has most recently posted the current status of the generator interconnection queue and studies at the following link:

https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/LGE_and_KU_GI_Study_Queue_Status_March_2,_2023.pdf.

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Question No. 55

Responding Witness: Lonnie E. Bellar / Stuart A. Wilson

Q-55. Refer to the Wilson Direct Testimony, page 15, footnote 16.

a. Explain the meaning of "uncertainties involved in estimates of solar projects' transmission costs." Include in the response, what specific elements are included in "transmission costs" and whether the solar facilities are assumed to reside in LG&E/KU's service territories.

b. By not including the uncertainties of transmission costs and interconnection delays in the modeling, explain why the model would not tend to over supply the portfolio with solar capacity.

A-55.

a. "Transmission costs" refers to transmission system upgrade costs. The uncertainty associated with solar projects' transmission costs stems from the difficulty in estimating transmission system upgrade costs in the context of the large number of proposed solar projects in the Companies' generator interconnection queue. It is assumed that a number of these proposed projects will not proceed, but it is impossible to know which projects to select for modeling purposes. Assuming which combination of projects proceed to commercial operation impacts the modeling of power flow on the transmission system, which is used to then identify system constraints and required upgrades. Rather than risk assignment of unneeded system upgrades to a particular solar facility based on an unknowable assumption, it was decided to assume the same cost of transmission for all, which in this case was no cost. With the exception of a wind proposal, all projects submitted in response to the Companies' RFP are located within the Companies' Balancing Authority ("BA").

b. Transmission system upgrade costs for a solar project typically are not a significant portion of the total project cost. Therefore, the inclusion of these costs would not have a material impact on the analysis.

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Question No. 56

Responding Witness: Philip A. Imber / Stuart A. Wilson

Q-56. Refer to the Wilson Direct Testimony, page 14, lines 25–27.

a. Explain whether LG&E/KU assumed that "complying with the Good Neighbor Plan" means that there would be no appeals or challenges to the proposed rule and that it would go into effect at the earliest possible date, and that date was then hard coded into PLEXOS as a constraint.

b. Explain whether LG&E/KU are aware of any other proposed EPA rule with such far reaching implications for electric generation fleets that went unchallenged.

c. Explain the reasonableness of assuming that the Good Neighbor Plan will not be tied up in the court system for years and, consequently, why LG&E/KU are choosing to retire coal units prematurely.

d. All else being equal, explain how the results of Stage 1 would change if the start date for Good Neighbor Plan compliance were to be delayed due to court challenges up to the Supreme Court level as has happened with previous EPA rules.

A-56.

a. See Wilson Direct Testimony, page 4, lines 9-13. The Companies assumed a two-year delay in the Good Neighbor Plan compliance deadline for the 2022 Resource Assessment. This assumption contemplated EPA establishing compliance mechanism relaxation(s) with the Good Neighbor Plan that expand the allocation market or retirement exemptions, effectively resulting in the ability to operate non-SCR units an additional two years. In the case of the Companies' 2022 Resource Assessment, this mechanism allows time for the replacement generation as a least-cost compliance option.

b. Generally, rules with far reaching implications are challenged. Nonetheless, the EPA has clear authority and obligation to implement a Cross State Air

Pollution Rule. The Companies have no basis to expect any potential litigation will successfully delay the implementation of the Good Neighbor Plan. See also the response to Question No. 41. Also, it is not prudent to assume that litigation will delay the implementation of the Good Neighbor Plan for purposes of complying with the law and provide reliable least-cost service to customers.

c. The Companies respectfully disagree with the request's assertion that "LG&E/KU are choosing to retire coal units prematurely." The EPA has clear authority and obligation to implement a Cross State Air Pollution Rule. The EPA is under three separate Consent Decrees to resolve three deadline suits related to EPA's duty to act on good neighbor SIP submissions for the 2015 ozone NAAQS. The Companies' proposals in this proceeding are a prudent and reasonable effort toward ensuring safe and reliable service at the lowest reasonable cost in an uncertain regulatory environment. See also the response to Question No. 41.

d. The Companies have not performed this analysis. However, because the Companies are already considering an effective two-year delay in the compliance deadline in the interest of a robust analysis, a delay of one to two years would not affect the proposed portfolio or its timing. With the proposed timeline, the Companies will avoid overhaul costs of $11 million for Mill Creek 2 in 2026, $26 million for Brown 3 in 2027, and $36 million for Ghent 2 in 2027. It is unclear to what extent these overhauls could be avoided with a delay greater than two years.

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Question No. 57

Responding Witness: Stuart A. Wilson

Q-57. Refer to the Wilson Direct Testimony, page 14, lines 31–34 and page 15, line 1.

a. Explain how PLEXOS accounts for resource reliability in determining whether to retire a resource or to add a resource.

b. Explain whether and how the Stage 1 results would change, if at all, if all potential resources were evaluated on an Effective Load Carrying Capability (ELCC) basis.

c. Explain whether the reliability measure used in PLEXOS evolves over time as a resource ages or as weather or other generating conditions change.

d. Explain whether and how PLEXOS accounts for transmission capacity and whether there is a difference between import and export capacity depending on LG&E/KU's need. If PLEXOS does not account for this, explain where in the resource modeling process this is accounted for.

e. Explain whether and how PLEXOS accounts for transmission costs. If PLEXOS does not account for this, explain where in the resource modeling process this is accounted for.

A-57.

a. PLEXOS's objective function is to determine the least cost portfolio that meets specified minimum target winter and summer reserve levels that the Companies have determined to be optimal. Each generating unit in the Companies' PLEXOS model is assigned seasonal firm capacity ratings, which count towards the targeted reserves.

b. The Companies have not performed this analysis but do not expect that it would materially change the proposed portfolio. See the response to part (a) and Section 5.2 of Exhibit SAW-1.

c. The minimum target reserve margins and the resources' firm capacity contributions are not assumed to change over time.

d. The Companies' PLEXOS modeling for this case does not account for transmission imports or exports. The potential for transmission imports was considered in determining the minimum reserve margin targets. See Exhibit SAW-1, Appendix D – Minimum Reserve Margin Analysis, Section 4.4.

e. The transmission system upgrade costs required to replace existing generation resources at the Mill Creek and Brown stations are included in the "Build Cost" associated with each individual expansion unit in PLEXOS. The Companies did not consider transmission system upgrade costs for other resource options.

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Question No. 58

Responding Witness: Lonnie E. Bellar / Charles R. Schram / David S. Sinclair / Stuart A. Wilson

Q-58. Refer to the Wilson Direct Testimony, page 15, lines 2–8 Assume that the Commission were to grant LG&E/KU's application as filed and in place.

a. Explain how LG&E/KU's resource portfolio would have performed during winter storm Elliot, including specifically whether rolling blackouts would have been necessary, and if so, whether they would have been better or worse.

b. Explain the reasons why the blackouts in LG&E/KU's balancing area on or about December 23, 2022, during winter storm Elliott were necessary. Include in the response (1) a separate explanation of why power could not be purchased from SEEM, MISO, PJM, or other sources; (2) whether LG&E/KU had sufficient transmission capacity to import sufficient power, and if not, why not; (3) whether any of the transmission interconnects had a Transmission Line Release (TLR) placed on them that would have prevented the import of power, and if so, the effect, if any, of that TLR; and (4) whether power was available that could have prevented the blackouts if LG&E/KU had additional transmission capacity to import from SEEM, MISO, PJM, or other sources.

c. State whether the Tennessee Valley Authority (TVA) was exporting power to other balancing areas during the blackouts in LG&E/KU's balancing area, and if so, why TVA was exporting such power.

A-58.

a. The results of this hypothetical scenario are unknown and would be based on uncertain assumptions regarding actual load, unit operations, system conditions, and external market developments (e.g., future supply and demand conditions in MISO and PJM) that would exist should weather conditions similar to winter storm Elliot occur in 2028 and beyond. The Companies plan for a 2028 winter reserve margin of 32.2% compared to a 2023 winter reserve margin of 37.4%, which is 244 MW higher than in 2028.

See the response to Question No. 53(f). This difference includes assuming higher load in 2028, more limited duration capacity (battery storage and dispatchable DSM), less dispatchable capacity, and lower total capacity. However, the Companies expect this lower reserve margin to be sufficient to cover the range of potential winter weather.

The Companies have used natural gas generation for decades to provide reliable service during extreme hot and cold weather events. That is one of the main uses of the Companies' fleet of simple cycle combustion turbine units. The curtailed output of the Cane Run Unit 7 combined cycle unit and the Trimble County simple cycle peaking units on December 23 was caused by a drop in pressure on the Texas Gas Transmission ("TGT") system due primarily to the failure of certain compressor equipment. TGT has identified and is implementing upgrades to their equipment and operating procedures to address the issue as described in the attached letter from TGT to the Companies. The changes TGT describes in its letter are in addition to the pipeline system changes TGT will make to accommodate the addition of the Mill Creek NGCC.

b. The rolling service interruptions that occurred in the LG&E/KU Balancing Authority ("BA") area on December 23, 2022, were necessary to maintain the reliability of the Bulk Electric System ("BES") because the LG&E/KU BA could not operate sufficient capacity at its Cane Run unit 7 NGCC and Trimble County simple cycle gas turbines to meet demand due to low gas pressure on the Texas Gas Transmission pipeline. NERC Standard EOP-011 requires Balancing Authorities to implement Operating Plans, including manual load shed (if necessary), to mitigate Capacity Emergencies within their Balancing Authority area.
   (1) In accordance with NERC Standard EOP-002-3,[56] the Companies made purchases regardless of cost. While power purchases from SEEM were not available, the Companies were able to purchase non-firm power on December 23, 2022 from PJM and MISO, but the RTOs curtailed those purchases during the rolling service interruption period due to constraints in their respective RTOs.
   (2) The Companies had sufficient transmission capacity to import sufficient power.
   (3) There were no Transmission Loading Relief ("TLR") actions needed on the transmission interconnects that would have prevented the import of power.
   (4) The Companies had sufficient transmission capacity to import sufficient power, but PJM and MISO curtailed power purchases as noted above.

c. TVA was not exporting any power to other BAs on December 23, 2022.

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[56] **https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-002-3.pdf, Section 2.6.2, pg 7.**

The attachment is being provided in a separate file.

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Question No. 59

Responding Witness: Stuart A. Wilson

Q-59. Refer also to the Wilson Direct Testimony, page 15.

a. Refer to lines 9–11. Explain the meaning of "the desirability of renewables predictability correlates with the level of fossil fuel prices."

b. Refer to lines 12–14.

(1) Explain the meaning of "dispatchable DSM and batteries are uneconomical for achieving minimum levels of reliability and meeting the significant need for energy created by the retirement of the three coal units."

(2) If dispatchable DSM is not economical for achieving minimum levels of reliability and energy needs, explain how these programs can be cost-effective for DSM purposes, but not for reliability or energy needs.

(3) If batteries are not economical for achieving minimum levels of reliability and energy needs, explain how LG&E/KU justify the proposed 125 MW/500 MWh battery to be online in 2026.

A-59.

a. The desirability of renewables means the tendency for PLEXOS to choose renewables, particularly solar, and is correlated with the absolute level of fuel prices; as the level of fuel prices increases, the amount of solar selected by PLEXOS increases. This is expected, as higher fuel prices provide more solar-related fuel savings and increase the price at which solar PPAs are economical.

b.

(1) In the Stage One, Step One analysis, dispatchable DSM and batteries were not selected by PLEXOS as part of the least-cost portfolio in any of the fuel price cases. For a given case, PLEXOS identifies the lowest-

cost portfolio subject to minimum reserve margin constraints, thus the reference to "minimum levels of reliability." As discussed on page 23 of Exhibit SAW-1, the fact that PLEXOS did not select DSM or batteries likely results from the cost of these resources relative to their limited duration, making them uneconomical to meet the significant need for energy created by coal unit retirements.

(2) Because of its limited duration, dispatchable DSM is uneconomical for replacing generation that is needed to operate for days at a time. But after energy needs and minimum levels of reliability are met, the Companies' analysis shows that dispatchable DSM is an economical means of increasing reliability beyond minimum levels. See section 4.6.2 in Exhibit SAW-1 beginning on page 36.

(3) See the response to Question No. 25(b).

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Question No. 60

Responding Witness: Stuart A. Wilson

Q-60. Refer to the Wilson Direct Testimony, page 15, lines 17–21. Explain and show that the results from the Step 1 of Stage 1 are least cost of other alternatives.

A-60. See Exhibit SAW-1, Section 4.4.1, pp. 22-23.

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Question No. 61

Responding Witness: Stuart A. Wilson

Q-61. Refer to the Wilson Direct Testimony, page 16, lines 1–9.

a. Explain how LG&E/KU selected the specific 22 different portfolios and whether these represented the least cost portfolios.

b. Of the portfolios based upon the Mill Creek NGCC and Ghent Unit 2 with selective catalytic reduction (SCR), confirm that Brown Unit 3 was assumed retired.

c. Explain whether the statement means that in Step 1 of Stage 1 that in PLEXOS the solar contracts were not assumed to begin at their RFP specified start date and the model was allowed to phase them in based on cost, uncertainty and other specified factors.

d. Explain the rationale for assuming that the contracts began on the RFP specified start dates. Include in the response whether PROSYM requires specified start dates or is it able to choose start dates based on cost and solar PPA uncertainty and any other specified factors.

A-61.

a. See section 4.4.2 of Exhibit SAW-1 beginning on page 24.

b. Confirmed.

c. See the response to Question No. 50(a).

d. In Stage One, Step One of the Resource Assessment, the Companies allowed PLEXOS to evaluate and select any or all of the solar PPA proposals at any time during the analysis period to understand which of the proposals were economically optimal to install by 2028. In Stage One, Step Two, the Companies sought to optimize the PLEXOS-selected solar PPAs on a practical, more detailed production cost basis by requiring PROSYM to start them on their RFP-response-specified start dates. The goal of this step was to understand which combination of PLEXOS-selected solar RFP responses would be least cost across the six fuel-price scenarios when paired with the two least-cost fossil-fueled portfolios selected by PLEXOS. For the results of this step to advance the analysis, they needed to be actionable, i.e., they needed to reflect production costs based on when the RFP respondents indicated their facilities would actually be available at the prices submitted. PROSYM requires specified start dates for every resource.

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Question No. 62

Responding Witness: Stuart A. Wilson

Q-62. Refer to the Wilson Direct Testimony, page 17, lines 3–4. Describe the methodology used to calculate the "average optimal amount of solar" for the three fuel price scenarios with a Mid coal-to-gas price ratio.

A-62. See section 4.4.2 of Exhibit SAW-1 beginning on page 24. The Companies calculated the PVRR for 22 portfolios with varying amounts of solar over a range of fuel price cases. Then, the Companies averaged the PVRR for each portfolio over the three fuel price scenarios with a Mid coal-to-gas ratio, and the portfolio with 637 MW of solar had the lowest average PVRR.

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Question No. 63

Responding Witness: Stuart A. Wilson

Q-63. Refer to the Wilson Direct Testimony, page 24, lines 2–3, which states, "Although these portfolios meet minimum reserve margin constraints in total, the differences in their full dispatchable reserve margins indicate that the reliability of these portfolios is very different."

a. Provide any analysis conducted that supports this statement.

b. Explain whether the model was required to meet a dispatchable reserve margin, the total reserve margin, or some other constraint.

c. Provide any examples in resource planning of other companies or jurisdictions where a dispatchable reserve margin is required.

A-63.

a. Recent reports by the North American Electric Reliability Corporation (NERC) and regional transmission organizations (RTO) PJM and MISO highlight potential risks to reliability in future years. A primary concern is a mismatch in the pace of transition away from dispatchable resources towards a resource mix that heavily relies on non-dispatchable, intermittent resources. Capacity shortfalls would result in load loss events during hours when high demand coincides with little or no intermittent generation. To address these reliability concerns, MISO and PJM are actively evaluating their respective capacity markets especially relating to intermittent capacity accreditation. See attached reports.

Intermittent and limited-duration resources such as battery storage and dispatchable DSM programs do not contribute to reliability in the same way that fully dispatchable resources do. See Appendix D (Minimum Reserve Margin Analysis) to Exhibit SAW-1, Section 5.2. The Companies' analysis shows that battery storage and dispatchable DSM have a less favorable impact on loss of load expectation ("LOLE") than a SCCT with the same capacity. Furthermore, solar and wind are modeled in the resource assessment as fixed energy resources. Their profiles are correlated with the temperatures, solar irradiance, and wind underlying the load forecast, but the Companies' analysis does not consider the potential for intra-hour fluctuations in solar or wind generation.

b. The PLEXOS model was required to meet total summer and winter reserve margin constraints.

c. The Companies are not setting a required dispatchable reserve margin but are pointing out how much of its reserve margin is met from dispatchable generation. See part (a).

The attachments are being provided in separate files.

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Question No. 64

Responding Witness: Charles R. Schram / David S. Sinclair

Q-64. Refer to the Wilson Direct Testimony, pages 28–30. Explain whether LG&E/KU considered any additional approaches for mitigating solar execution risk besides solar asset ownership.

A-64. The Companies did consider and implement additional risk mitigation. See Sinclair Direct Testimony page 21, lines 10-23 and page 22, lines 1-5.

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Question No. 65

Responding Witness: Stuart A. Wilson

Q-65. Refer to the Wilson Direct Testimony, pages 30–34. Confirm that no battery resources besides Brown BESS were evaluated in SERVM as part of Stage 3, Step 2.

A-65. Confirmed.

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Question No. 66

Responding Witness: Stuart A. Wilson

Q-66. Refer to the Wilson Direct Testimony, page 16, lines 12–18, page 17, lines 1–9 and Exhibit SAW-1, Appendix B, pages 55–59.

a. Confirm that in both the PLEXOS and PROSYM model runs, individual fuel price forecasts were not used and that the coal to gas (CTG) ratio was the variable used.

b. Given Europe's decreasing dependence on Russian natural gas and an increasing demand for U.S. natural gas exports, explain why natural gas prices will not remain relatively high into the future.

c. Referring to Appendix B, page 59, Table 38.

(1) Explain the basis is for the individual coal price forecasts and how each coal price forecast was selected to pair with the respective natural gas prices.

(2) Explain the basis for selecting a mid-CTG ratio, regardless of natural gas price forecasts, as the expected CTG ratio for use in PLEXOS and PROSYM model runs.

(3) Explain why the Companies believe that the atypical CTG price ratios are atypical and less likely to happen versus the mid-CTG ratios.

A-66.

a. Not confirmed. The CTG ratio was used to develop coal price forecasts. PLEXOS and PROSYM use the same coal and natural gas prices. As discussed in the referenced section, low, mid, and high natural gas prices are based on recent market quotes and the Energy Information Administration's 2022 Annual Energy Outlook. Then, a range of CTG ratios was used to develop coal price forecasts as a function of projected gas prices.

b. Natural gas prices have decreased significantly since the CPCN application was filed. (See the response to Question No. 33(b).) The Companies are not suggesting natural gas prices will remain at a particular level. Also, Europe has indicated a strong preference for reducing the volume of natural gas that it uses in the future.[57]

c. For additional information regarding the development of the fuel prices the Companies used in their modeling, see Exhibit SAW-1 Appendix E, "2022 Resource Assessment Fuel Price Forecasts."

   (1) See the first two paragraphs on page 58 in Exhibit SAW-1 Appendix B.

   (2) See page 57 in Exhibit SAW-1 Appendix B.

   (3) The Mid CTG ratio was computed as the average coal-to-natural gas ratio over a 10-year period to average out short-term variability due to differences in the responsiveness of coal and natural gas markets to changing market fundamentals. Not surprisingly, at this 10-year average, the costs of coal and NGCC energy are very similar. Because coal and gas are market-priced commodities that are economic substitutes, the Companies expect the CTG ratio to revert to its historical average over time as short-term variances in the Mid CTG ratio balance production, consumption, and pricing of each commodity. The atypical CTG ratios were computed over shorter periods (i.e., 1 or 6 years) and are not expected to persist over the entire analysis period. At the atypical CTG ratios, the costs of coal and NGCC energy are not similar and market pressures would tend to move the ratio back to the long-term average, as seen historically. The atypical CTG ratios are labeled atypical in the context of this analysis because they are modeled to persist over the entire analysis period, which would be atypical.

[57] See, for example, **"**The EU Needs Alternatives to Russian Energy. Here's the Plan.", Council on Foreign Relations, December 13, 2022 https://www.cfr.org/in-brief/eu-needs-alternatives-russian-energy-heres-plan

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Question No. 67

Responding Witness: Stuart A. Wilson

Q-67. Refer to the Wilson Direct Testimony, Exhibit SAW-1, Appendix B, page 58, footnote 48. If not already provided, provide the cost benefit study showing the retirement of the Mill Creek Unit 2, Ghent Unit 2 and Brown Unit 3 in 2028 and six years before the end of the book depreciation lives of Mill Creek Unit 2 and Ghent Unit 2 (2034). Include in the response a description of the steps and assumptions used in each analysis. Also provide the analysis in excel spreadsheet format with all cells visible and unprotected.

A-67. Exhibit SAW-1 is a summary of the analysis that demonstrates that the retirements of Mill Creek Unit 2, Brown Unit 3, and Ghent Unit 2 are least cost. See Exhibit SAW-1, particularly Section 4, Section 5, and Appendix D. All work papers for this analysis are provided as Exhibit SAW-2.

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Question No. 68

Responding Witness: Stuart A. Wilson

Q-68. Refer to the Wilson Direct Testimony. Provide the six optimal portfolios generated in Step 1 of Stage 1 of the resource assessment. For each portfolio, show which resource additions occur each year throughout the modeling period.

A-68. The table below shows the resources selected by PLEXOS through 2028 for each of the six fuel price scenarios evaluated in Stage One, Step One of the resource assessment.

	Fuel Price Scenario					
Resource	Low Gas, Mid CTG	Low Gas, High CTG	Mid Gas, Mid CTG	High Gas, Low CTG	High Gas, Mid CTG	High Gas, Curr CTG
Brown Unit 12 (621 MW NGCC)	2028	2028	2028			2028
Mill Creek Unit 5 (621 MW NGCC)	2027	2027	2027	2027	2027	2027
Song Sparrow PPA (Clearway Energy; 104 MW)			2027	2027	2027	2027
Grays Branch PPA (ibV; 138 MW)					2027	2027
Nacke Pike PPA (ibV; 280 MW)				2027	2027	2027
Gage Solar PPA (BrightNight; 115 MW)					2027	2027
Golden Solar PPA (National Grid Renewables; 100 MW)						2027
Idlewild Solar PPA (Orion; 685 MW)						2027
Marble Hill PPA (BrightNight; 500 MW)						2027
Dyers Spring PPA (BrightNight; 200 MW)						2027
Cumberland Solar PPA (Narenco; 100 MW)						2028
Silverstone Solar PPA (Narenco; 100 MW)						2028

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Question No. 69

Responding Witness: Charles R. Schram

Q-69. Refer to the Direct Testimony of Charles Schram (Schram Direct Testimony), page 5, line 19.

a. Describe the magnitude of the price change for the five RFP respondents who modified their proposal as a result of the IRA.

b. Provide both the pre- and post-IRA RFP responses for the five RFP respondents who modified their proposal as a result of the IRA (or identify them in the record if already provided).

c. Explain whether the respondents who modified their proposals gave justification for the change (i.e., identify specific programs within the IRA that would impact their cost).

d. Confirm that the Department of Treasury has issued some initial guidance on certain federal tax credit provisions, with further guidance still pending, since the passage of the IRA. State whether that guidance is likely to affect the cost of facilities proposed in the RFP responses, and if so, explain how. Explain whether LG&E/KU will reissue the RFP or allow respondents to further adjust their bids based on that guidance

A-69.

a. The following five offers were updated. The updated pricing did not result in a change in economics such that the Companies pursued any of the revised offers.
   1. Solar + Storage project: Energy cost reduced by \$3-\$4/MWh. Storage reduced by \$1.00-\$1.50/kW-month.
   2. Pumped hydro project: Reduced by \$2.25/kW-month.
   3. Storage-only project: Reduced by \$0.67-\$0.87/kW-month.
   4. Storage-only project: Reduced by 0.70/kW-month.
   5. Solar + Storage project: Energy cost reduced by \$11/MWh; Storage reduced by \$0.03/kW-month.

b. See Exhibit CRS-2 for the pre-IRA RFP responses. For post-IRA updates see attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

c. Of the five updated offers listed in part a), the first two cited the domestic content and community energy bonus provisions of the IRA. The final three did not cite specific IRA provisions.

d. Confirmed. The owned solar projects in Mercer County and Marion County and the Brown BESS will naturally capture and reflect the IRS regulations regarding the IRA in place at the time of their construction. Three of the four PPAs contain specific price reopener provisions and, to the extent IRA provisions are reflected in the future price of new solar PPAs, the Companies expect that the final prices from the re-opening process will reflect the then current IRS regulations. The Companies do not currently anticipate re-opening the RFP or issuing a new RFP given the need to comply with the timing of the Good Neighbor Plan.

The entire attachment is confidential and provided separately under seal.

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Question No. 70

Responding Witness: Lana Isaacson

Q-70. Refer to the Direct Testimony of Lana Isaacson (Isaacson Direct Testimony), page 7–8. Explain whether the Residential Online audit program is a substitute for a third-party verification to ensure that the self-installation was completed.

A-70. The proposed Residential Online Audit program is not a substitute for third-party verification for self-installation measures. The Companies plan to engage with a separate entity for third-party verification of self-installed measures if a rebate is submitted to the Companies.

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Question No. 71

Responding Witness: Lana Isaacson

Q-71. Refer to the Isaacson Direct Testimony, pages 8–9. Explain whether the new federal standards for lighting may have negatively impacted the cost-effectiveness for the Business Solutions program, and if so, explain how.

A-71. The federal standards for lighting issued in 2022 focused on general service or screw-in lamps, which primarily impact the residential customer segment. Therefore, the new federal standards for lighting did not impact the cost-effectiveness for the Business Solutions program.

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Question No. 72

Responding Witness: Lana Isaacson

Q-72. Refer to Isaacson Direct Testimony, page 14–15, regarding adoption of DSM programs that are not cost-effective. Explain the process LG&E/KU uses to determine adoption of DSM programs that are not cost-effective.

A-72. As part of the planning process, the Companies consider past Commission precedent, customer interest, adoption rates of existing programs, and input from the DSM Advisory Group in determining any program to propose to the Commission, including any program with a TRC less than 1.0. The Companies look at ways to maximize the cost-effectiveness before submitting any program for Commission consideration. Furthermore, the Companies seek to present a suite of DSM programs that, like the proposed DSM/EE Program Plan, is cost-effective as a whole and has a TRC greater than 1.0.

The Companies use multiple means to monitor adoption of the programs, including those that are cost-effective or not cost-effective:

- Deploy marketing and communication strategies for each of their DSM/EE programs to increase customer awareness and adoption of the offerings;
- Review marketing initiatives for their effectiveness, including initial open and click-thru rates to the number of application requests that are submitted thereafter;
- Monitor the program targets against actual data to stay abreast of overall performance;
- Work closely with the Companies' third-party vendors to regularly exchange ideas and provide feedback on best practices; and
- Complete third-party EM&V review the processes and performance, including recommendations for program improvement.

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Question No. 73

Responding Witness: Lana Isaacson

Q-73. Refer to the Isaacson Direct Testimony, page 15–16.

a. Provide a breakdown of the cumulative energy (MWh) and demand (MW) savings levels for each program in each year from 2024-2030.

b. Clarify whether the MWh savings represented in the Energy Efficiency Portfolio table are first-year savings, or lifetime savings. Provide the first-year or lifetime savings values not included in the table.

c. Explain how the savings represented in these tables are linked to the Cross-Sector DSM Potential Study Projection provided in Exhibit LI-1, and the Demand Response Assessment provided in Exhibit LI-2. Provide any supporting workpapers used to determine the 2024-2030 portfolio savings levels assumed based on these potential studies.

d. Refer to the Isaacson Direct Testimony, Exhibit LI-1, Tables 8-10. Provide all supporting workpapers used to determine the Economic and Achievable potential levels of savings.

A-73.

a. See the Excel spreadsheet titled "LGE KU Program Measure Inputs FINAL – Public," provided as part of Exhibit LI-6. The energy and demand savings in kWh and kW for each program in each year from 2024-2030 are shown in the "Program Summary" tab and in the individual tabs for each program.

b. The MWh savings represents the first-year savings. The Companies did not calculate the lifetime savings values.

c. See the Excel spreadsheet titled "LGE KU Program Measure Inputs FINAL – Public," provided as part of Exhibit LI-6. The Cross Sector DSM Potential Study Projections and Demand Response Assessment ties to the Companies' proposed Plan as described in Section 1.3 of Exhibit JB-1. The potential studies inform the program design in terms of types of measures to offer and projected participation levels. For example, the studies indicated that commercial lighting potential is a finite resource of available potential as the market quickly adopts LED lighting equipment. As a result, the Companies' Plan accounted for this by declining the participation of LED measures in later years of the Plan beginning in 2029.

   The product assumptions of the Demand Response Assessment Exhibit LI-1 are in Appendix B.

d. See the response to part (c).

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Question No. 74

Responding Witness: Lana Isaacson

Q-74. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-1, Table 1-1, pages 14–16. LG&E/KU are providing summaries of proposed modifications to each program.

a. Explain why the Appliance Recycling Program ended in 2018 and explain why it has a proposed startup date in 2026.

b. Explain, if any, how many industrial customers opted out of the Business Solutions (formerly Nonresidential Rebates) due to the incentive cap.

c. Explain the budget impact for the proposed modification of removing the incentive cap for the Business Solutions program.

A-74.

a. Several DSM programs (including Appliance Recycling) ended in 2018 because the programs were no longer cost-effective. The Companies propose to restart Appliance Recycling in 2026 because it is again cost-effective due to higher avoided costs of capacity and energy. The Companies anticipate that customers have accumulated secondary/supplemental appliances during the period of time the Companies did not offer the program.

b. Currently 53% of eligible industrial customers have elected to opt-out of the DSM/EE programs. However, the Companies do not record the precise reason for their opt-out and are not aware how many eligible industrial customers opted out due to the incentive cap.

c. There is an expectation that the removal of the Business Solutions (Nonresidential Rebates) incentive cap will increase participation. The current Nonresidential Rebates incentives budget for 2022-2025 is an average of $2.212 million per year. This is compared to the proposed Business Solutions (Nonresidential Rebates) program's incentives budget for 2024-2030 at an average of $2.630 million per year.

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Question No. 75

Responding Witness: John Bevington

Q-75. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-1, page 19, Table 1-4.

a. While the Commission understands that Low-Income programs historically have not had a TRC score above 1.0, explain whether LG&E/KU's modifications to the Income-Qualified programs would potentially increase the cost-effectiveness over time.

b. It appears that the findings in the DSM-EE Program Plan determined that the Residential online audit program has a tendency not to be cost-effective. State whether LG&E/KU agree with that characterization. If not, please explain. Also, explain whether LG&E/KU have any intention of terminating or modifying this program if it underperforms.

A-75.

a. Yes, the Companies' modifications to the Low-Income programs should increase the cost-effectiveness of the programs. Due to the nature of the modifications, specifically adding a multi-family ("MF") whole-building component to the program, the TRC score is slightly better mainly due to the ability of the MF portion to reach more residences. For instance, it is more cost-effective for the Companies to perform energy improvements to a ten-unit apartment complex at one time versus performing energy improvements to ten individual residences.

b. Because an online audit program is primarily educational, the Companies agree with the characterization. The Companies have paired this offering with residential rebates, a historically cost-effective program, as a means to increase the overall TRC and hopefully justify the presence of the audit program in the filed plan.. In addition to being a program that the DSM Advisory Group members advocated for, the audit should be a valuable tool for customers, and one that enables customer investment in energy efficient measures with the possible assistance of the rebates in the offering. The Companies will continually evaluate all programs to determine a program's value, cost-effectiveness and need, and will seek Commission approval if modifications or termination of programs are warranted.

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Question No. 76

Responding Witness: Lana Isaacson

Q-76. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-1, page 29, Table 3-3.

a. Explain why LG&E/KU are proposing an annual budget for the incentives at $0, considering the Income-Qualified Solutions have an incentive structure of $1,650 in program services per single-family household and $750 per multifamily unit.

b. Explain why LG&E/KU concluded that a 3.0 percent labor escalation rate is appropriate.

A-76.

a. The "incentive" structure for this program provides these improvements and/or measures for eligible customers as services and not directly in a monetary format. Thus, the incentive line is at $0 and the implementation row of Table 3-3 reflects the value of these dollars for program services.

b. The 3.0 percent labor escalation rate is consistent with historic cost-of-living market adjustments (without considering recent high inflation).

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Question No. 77

Responding Witness: John Bevington

Q-77. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-1, page 41. Explain why LG&E/KU did not propose a separate program for Optimized Charging and instead included it with Connected Solutions.

A-77. Optimized charging was included with Connected Solutions due to the potential overlap with vendor solutions. For example, some vendor solutions could connect to a charging station as they would to a thermostat or other device. Thus, program costs savings could be achieved. Further, the current pool of charging stations is still relatively small compared with the number of thermostats in customer's homes. In the future, depending on the success of the offering and available technology solutions, managed charging could be a standalone offering.

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Question No. 78

Responding Witness: Lonnie E. Bellar

Q-78. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-1, page 48. LG&E/KU state that AMI is currently being deployed to all customers. Explain when LG&E/KU anticipate having AMI fully installed throughout their entire service territory.

A-78. The Companies anticipate having AMI fully installed throughout the entire service area by the 1st Quarter of 2026, consistent with Case Nos. 2020-00349 / 2020-00350 Exhibit LEB-3 Figure 12 and the quarterly reports filed with the Commission in the above referenced cases. Each quarterly report gives an update on progress and reports any significant schedule changes.[58]

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[58] See https://psc.ky.gov/ViewCaseFilings/2020-00349/Post or https://psc.ky.gov/ViewCaseFilings/2020-00350/Post for the most recent quarterly report and AMI Project Schedule.

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Question No. 79

Responding Witness: Lana Isaacson

Q-79. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-1, page 49, Table 4-4 and page 50, Table 4-6. Regarding the Peak Time Rebates Program:

a. Explain LG&E/KU's intentions for year 1 of the program.

b. Provide cost justification for the year 1 administration program costs considering the program is not expected to start until 2025.

c. Explain whether LG&E/KU are limiting participation to 92,500 for each LG&E and KU service territory separately or combined.

A-79.

a. The Companies plan to begin IT implementation activities in 2024 in preparation for 2025 deployment of Peak Time Rebates. The remaining IT implementation activities would be completed in 2025.

b. To prepare for the 2025 deployment, the Companies allocated a portion of the total IT implementation costs in 2024.

c. The Companies are not limiting participation to 92,500 participants in each of the service territories. The Companies developed 92,500 for both KU and LG&E (185,000 combined) as a participation target based on research of other similar utility companies with Peak Time Rebate programs.

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Question No. 80

Responding Witness: John Bevington

Q-80. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-3, page 2, Table 1. Provide the emails received from Mountain Association (Chris Woolery) with regards to Full Project Costs, Maximum Project EUL, and kWh Savings per project.

A-80. See attached.

The attachment is being provided in a separate file.

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Question No. 81

Responding Witness: Lana Isaacson

Q-81. Refer to 2024-2030 DSM-EE Program Plan, Exhibit JB-3, page 3–5.

a. Explain, if at all, what customer classes the target market for the PAYS program would be.

b. Explain, if possible, what would need to occur for the PAYS program to become cost-effective.

c. Explain how, with a 0 or 3 percent interest rate, the cost effectiveness of the PAYS program does not change regardless of participation count.

A-81.

a. PAYS is targeted for the residential customer.

b. To become cost-effective with a TRC score greater than 1.0, the benefits associated with the PAYS program would need to increase and/or the costs associated with the PAYS program would need to decrease. Specifically, for this program:

1. the assumed savings per project needs to **increase,**
2. the avoided capacity or energy costs need to **increase,**
3. the participant's incremental project costs need to **decrease,**
4. the utility's administration costs need to **decrease**, or
5. some combination of the above.

c. The issue here is related to the interest the customer pays. Thus, if at 0% the program is not cost-effective, any higher interest rate does not improve the score. Also see the response to part (b).

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Question No. 82

Responding Witness: Lana Isaacson

Q-82. Refer to Exhibit LI-1, Demand Response Assessment Exhibit LI-1, page 9, Figure 1.

a. Identify which demand response programs listed in Figure 1 are included in the proposed DSM program categories identified in the Application, page 16.

b. If any of the demand response programs listed in Figure 1 are not included in the proposed DSM programs, explain why not.

A-82.

a. The Companies assume the question reference is to Exhibit LI-2, which is the Demand Response Assessment. The naming conventions used in the Companies' proposed DSM programs differ from those used in the Demand Response Assessment in Figure 1. Further, the proposed programs outlined in the Companies' DSM Plan may include multiple components that could be considered stand-alone programs in the Demand Response Assessment. The table below maps proposed DSM programs and components in the Companies' Plan to those listed in Exhibit LI-2.

DSM Plan DR Programs	DSM Plan DR Program Component	Demand Response Assessment Program
Connected Solutions	Residential and Nonresidential Demand Conservation	Existing HP/AC DLC Program – Two Way Existing HP/AC DLC Program – One Way Existing Pool Pump DLC Program

		Existing WH DLC Program
	Bring your own Device	Res DLC BYOT
	Optimized Charging	NA
	Online Transactional Marketplace	NA
Peak Time Rebates	N/A	Res CPR-No Enablement Res Behavioral DR
Nonresidential Demand Response	N/A	Com. Curtailment-AutoDR Industrial Curtailment-AutoDR

b. For Figure 1 programs not in plan, see the table below:

Item #	Figure 1 Name	Explanation
1	DVR	The Companies plan to implement Conservative Voltage Reduction (“CVR”) after AMI implementation is complete.
2	C&I Int. Rates	This is a base rate design offering and was not considered in the current DSM/EE Plan.
3	Res TOU	This is a base rate design offering and was not considered in the current DSM/EE Plan.
4	Res CPP-With Enablement	This is a base rate design offering and was not considered in the current DSM/EE Plan.
5	Res CPP-No Enablement	This is a base rate design offering and was not considered in the current DSM/EE Plan.
6	Res CPR-With Enablement	This is a base rate design offering and was not considered in the current DSM/EE Plan.

7	Ind RTP	This is a base rate design offering and was not considered in the current DSM/EE Plan.
8	New HP/AC DLC Program	TRC ratio was low and focus was put on new DR offerings like PTR and BYOT.
9	C&I Curtailment-Backup Gen	TRC ratio was low and this is a base rate design offering thus was not considered in the current DSM/EE Plan.

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Question No. 83

Responding Witness: Lana Isaacson

Q-83. Refer to Exhibit LI-2, 2023 LG&E and KU Demand Response Assessment, page 1. Explain why LG&E/KU did not select all potential Demand Response programs to be screened.

A-83 See the response to Question No. 82 part (b).

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Question No. 84

Responding Witness: Christopher M. Garrett

Q-84. Refer to Exhibit_LI-3_-_KU_DSMRC_Calculations.xlsx, Tab DCCR2, cell J15. Explain how KU derived a 7.4 percent Rate of Return on DSM Rate Base.

A-84. KU developed the 7.40% estimated Rate of Return on DSM Rate Base using a capital structure comprised of approximately 47% debt and 53% equity. A weighted average cost of debt of 2.13% and a 5.27% weighted average cost of equity were assumed. The cost of equity utilized reflects KU's most recently awarded rate case ROE of 9.425% adjusted for a 50 bps adder as discussed in the response to Question No. 7.

Weighted avg. cost of debt: 47% * 4.55% = 2.13%
Weighted avg. cost of equity (after-tax): 53% * 9.925% = 5.27%

KU notes that this calculation is an estimate and will be updated to reflect the actual cost of capital on an annual basis as part of the DSM balancing adjustment (DBA) calculation.

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Question No. 85

Responding Witness: Christopher M. Garrett

Q-85. Refer to Exhibit_LI-4_-_LGE_Electric_DSMRC_Calculations.xlsx, Tab DCCR2, cell J15. Explain how LG&E derived a 7.36 percent Rate of Return on DSM Rate Base.

A-85. LG&E developed the 7.36% estimated Rate of Return on DSM Rate Base using a capital structure comprised of approximately 47% debt and 53% equity. A weighted average cost of debt of 2.09% and a 5.27% weighted average cost of equity were assumed. The cost of equity utilized reflects LG&E's most recently awarded rate case ROE of 9.425% adjusted for a 50 bps adder as discussed in the response to Question No. 7.

Weighted avg. cost of debt: 47% * 4.45% = 2.09%
Weighted avg. cost of equity (after-tax): 53% * 9.925% = 5.27%

LG&E notes that this calculation is an estimate and will be updated to reflect the actual cost of capital on an annual basis as part of the DSM balancing adjustment (DBA) calculation.

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Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 86

Responding Witness: Tim A. Jones / Stuart A. Wilson

Q-86. State whether DSM programs were integrated into any modeling performed to determine load forecast or capacity requirements.

A-86. See Section 3.5 of Exhibit TAJ-1, which begins on page 19. Figure 21 shows load forecast reductions assumed as a result of the proposed non-dispatchable DSM-EE programs. The Companies' existing and proposed dispatchable DSM programs were evaluated in PLEXOS when evaluating the optimal resource portfolios. See Exhibit SAW-1, Section 3.2 – *Demand Side: DSM Resources*.

KENTUCKY UTILITIES COMPANY
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Question No. 87

Responding Witness: Stuart A. Wilson

Q-87. Refer to the executive summary of Exhibit SAW-1 (Reserve Margin Analysis), which states, "The cost of capacity for this analysis was based on a response to the Companies' June 2022 RFP for simple-cycle combustion turbine ("SCCT") capacity and was 34% lower than the cost of SCCT capacity used in the 2021 IRP Reserve Margin Analysis. Based on the updated load forecast and after factoring in the updated cost of SCCT capacity, the minimum reserve margin target for the summer did not change from 17%, but the minimum winter reserve margin target decreased from 26% to 24%."

a. Identify the specific response to the RFP being referred to.

b. Explain the drivers behind the cost difference of 34% for the SCCT in the RFP responses versus the 2021 IRP Reserve Margin Analysis.

c. Explain whether the cost of SCCT capacity used in the 2021 IRP Reserve Margin Analysis is the same as the cost for SCCT resources in LG&E/KU's IRP modeling.

d. Provide the SCCT costs in the 2021 IRP analysis, current analysis, 2022 RFP response, 2021 Reserve Margin Analysis, and 2022 RFP Reserve Margin analysis.

e. Explain how a reduction in capacity cost led to a reduction in the reserve margin target.

A-87.

a. The updated SCCT capacity cost is based on an RFP response from LG&E/KU's Project Engineering group. See Proposal No. 108 in Table 42 in Exhibit SAW-1, Appendix B.

b. Capital, fixed O&M, and firm gas transport costs are 23%, 85%, and 30% lower, respectively.

c. They are the same.

d. See the table below.

Input assumption	**2021 IRP analysis, 2021 Reserve Margin analysis**	**Current analysis, 2022 RFP response, 2022 RFP Reserve Margin analysis**
Capital Cost ($/kW)	907	700
Fixed O&M ($/kW-yr)	23.5	3.6
Firm Gas Transport ($/kW-yr)	22.2	15.6
Escalation Rate	1.42%	1.47%
Discount Rate	6.41%	6.43%
Carrying Charge ($/kW-yr)	112.7	73.9

e. Changes to the minimum reserve margin targets are the result of changes to both load and SCCT capacity costs. All other things equal, lower capacity cost leads to an increase in minimum reserve margins (see Exhibit SAW-1, Appendix D (*Reserve Margin Analysis*) at page D-9, Figure 5). For summer reserve margin, the impacts of load and capacity cost changes are offsetting. For winter reserve margin, the impact of load changes more than offsets the impact of a lower capacity cost.

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Question No. 88

Responding Witness: Stuart A. Wilson

Q-88. Refer to the Reserve Margin Analysis, Table 1. Explain whether the values for the dispatchable and nondispatchable margins are inputs or outputs of the model. Specifically, explain whether the model is required to meet certain portion of the PRM with dispatchable resources.

A-88. The total reserve margin values in Table 1 (i.e., 17% in the summer and 24% in the winter) are outputs from the reserve margin analysis. The split between dispatchable and intermittent resources was provided for informational purposes. Only the total reserve margins are a constraint in PLEXOS.

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Question No. 89

Responding Witness: Stuart A. Wilson

Q-89. Refer to workpaper FirmCapacityWinter, FirmCapacityMonthly, CapRatings, and CapMax within the PLEXOS folder of the SAW Workpapers provided as part of the Joint Application.

a. Explain what the values in each workpaper represent and whether they were an input to the capacity expansion step of PLEXOS.

b. Confirm that LG&E/KU assumed a 0 percent firm capacity contribution from solar in winter.

c. Provide a single file with the installed, unforced, and firm capacity for each of LG&E/KU's existing and planned (or under consideration) thermal resources.

d. Explain why the energy storage resources under consideration are not included in these files and provide what their values would be in each file.

e. Explain why the NewNGCC and NewSCCT resources are assumed to have firm capacity that exceeds their MaxCap.

A-89.

a. **CapMax** values are the average of summer and winter net capacity figures and were used as the basis for fixed cost calculations such as stay-open costs and capital costs and recovery.

FirmCapacityWinter values are the winter net capacity figures and were used to calculate total capacity reserves for model runs in which target minimum winter reserve margin was a constraint.

FirmCapacityMonthly values are the monthly net capacity figures and were used to calculate total capacity reserves in both winter and summer for model runs in which target minimum summer and winter reserve margins were both constraints. Such model runs take more time to run, so these runs were only used as needed.

CapRatings values reflect the seasonal net monthly ratings for existing thermal units on an ICAP basis. For the RFP thermal units, the CapRatings values reflect adjusted UCAP figures to generically account for unplanned and planned outages. See the response to Question No. 43.

b. Confirmed.

c. See attached. The UCAP values reflect the ICAP values less the assumed unplanned outage rates for each unit.

d. The capacity figures for the energy storage resources are shown in the following confidential files in Exhibit SAW-2. There is no CapRatings file for energy storage resources because their monthly ratings are the same at their maximum capacities.
   - \02_PLEXOS\CONFIDENTIAL\CapMax_22RFP.csv
   - \02_PLEXOS\CONFIDENTIAL\FirmCapacityMonthly_22RFP.csv
   - \02_PLEXOS\CONFIDENTIAL\FirmCapacityWinter_22RFP.csv

e. Capacity figures for NGCC and SCCT units are typically higher in the winter and lower in the summer. The "MaxCap" (a.k.a., CapMax) figures are the average of summer and winter capacities. See the response to part (a). The FirmCapacityWinter values reflect winter capacity only and are therefore higher than the MaxCap (average) values.

The attachment is being provided in a separate file.

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Case No. 2022-00402

Question No. 90

Responding Witness: Tim A. Jones / Stuart A. Wilson

Q-90. Refer to the LG&E/KU's 2021 IRP in Case No. 2021-00393.[5] Also refer to the pending application in this case. Provide a comparison of:

a. The load forecast, prior to the inclusion of EE, and DER. Provide a workpaper including the hourly load forecast of both analyses and explain the main drivers behind any changes (identify the workpaper if a responsive workpaper has already been provided in this matter).

b. The EE forecast. Provide a workpaper including the hourly EE forecast of both analyses and explain the main drivers behind any changes (identify the workpaper if a responsive workpaper has already been provided in this matter).

c. The DER forecast. Provide a workpaper including the hourly EE forecast of both analyses and explain the main drivers behind any changes (identify the workpaper if a responsive workpaper has already been provided in this matter).

d. Technology costs. Provide a workpaper outlining the fixed and variable O&M, and incremental capital expenditures for all existing resources, and the fixed and variable O&M and capital costs for all resources available for selection by the model (identify the workpaper if a responsive workpaper has already been provided in this matter).

e. Capacity Contribution by resource type for all new resources and by unit for existing and planned resources. Provide a list of the capacity contribution of all existing, planned, and under consideration resources and explain whether those changed between the two analyses. If yes, please explain why and

[5] Case No. 2021-00393, Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (filed Oct 19, 2021), 2021 IRP.

provide any relevant studies (identify the workpaper if a responsive workpaper has already been provided in this matter).

f. Target Reserve Margin. Explain whether the two analyses used the same target reserve margin.

g. Coal retirement options. Explain whether and how the IRP analysis investigated economic retirement of coal units, explain any differences in how coal retirements were handled in this case as compared to the IRP for each coal unit, and explain each basis for the different treatment.

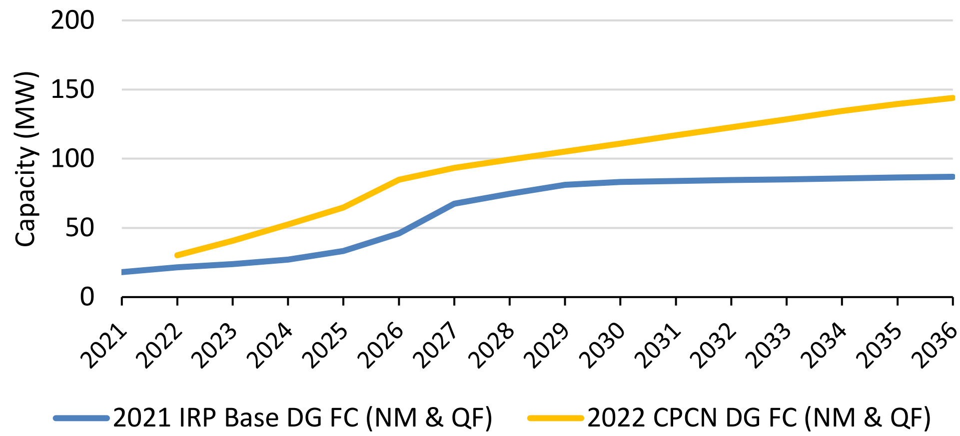
h. Fuel and commodity prices. Provide a workpaper or identify the location of a workpaper in this record, including the gas, coal, and market prices used in each analysis.

A-90.

a. The hourly load forecast is prepared as a function of monthly energy forecasts that already reflect the impact of non-dispatchable DSM-EE and customer-initiated energy efficiency savings. Therefore, hourly load forecasts without DSM-EE and customer-initiated energy efficiency savings do not exist for the IRP or CPCN filings. See page 6 of the Jones Direct Testimony: Figure 1 is a comparison of the annual load forecasts from the IRP and CPCN filing, with and without the BlueOval SK load; lines 7 through 15 below Figure 1 on that page discusses the main drivers of change.

b. See the response to part (a). An hourly forecast of energy efficiency is not available. However, see Figure 20 on page 21 of Exhibit TAJ-1 for a comparison of the amount of RS and GS energy efficiency in the IRP versus the CPCN forecast. Note that while not explicitly attributing energy efficiency to specific DSM-EE programs, the IRP did in fact have a significant amount of energy efficiency assumed in the load forecast. See Figure 21 on page 22 of Exhibit TAJ-2 to view an estimate of the allocation of EE to DSM-EE programs and customer-initiated energy efficiency, which is assumed to be accelerated by the IRA.

c. The Companies assume that "DER" refers to distributed generation and further assume that the reference to "hourly EE forecast" was intended to refer to the DER forecast. See the graph below for a comparison of the annual distributed generation capacity forecasts from the 2021 IRP and the current CPCN filing.



The projected increase from the 2021 IRP capacity forecast to the 2022 CPCN forecast is driven by several factors which resulted in a higher customer forecast. In the near-term, the forecast reflects higher-than-forecasted solar adoption in 2020-2021. As stated in the 2021 IRP Vol. 1 regarding the solar base customer forecast: "After 2021, net metering customer growth returns to levels experienced before mid-2019 when growth increased due to the passing of Kentucky House Bill 100 and the then-planned expiration of the ITC." This return to earlier, slower rates of adoption did not occur and almost a year and a half more of adoption data shows that the rapid growth seen post-2019 has continued. In the long-term, the CPCN forecast was modified to assume customers would continue to install solar (albeit with smaller arrays) after the 1% cap is reached. This new assumption stipulated that post-cap, new net-metering customers will be compensated at the SQF rate for energy exported to the grid.[59]

For the hourly distributed solar forecast, see Exh. TAJ-3 at:
Hourly_Forecast_Updates\PV\PV_newHourly.xlsx.

d. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

e. The table below shows capacity contribution assumptions by resource type from the 2021 IRP and the pending application in this case.

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[59] The assumption of the 10-year extension of the investment tax credit (ITC) included in the 2021 IRP mirrored the actual extension which took place (albeit 26% vs. 30%), so the ITC is not a significant driver of difference between the two forecasts. The only adjustment related to the ITC was that the continued linear growth of qualifying facilities customers was level-shifted upwards to account for the slightly higher ITC percentage.

Resource Type	2021 IRP		Pending Application	
	Summer	**Winter**	**Summer**	**Winter**
Coal	100%	100%	100%	100%
NGCC	100%	100%	100%	100%
SCCT	100%	100%	100%	100%
Solar	78.6%	0%	78.6%	0%
Wind	24%	32%	24%	32%
2-hour Battery Storage	NA	NA	42%	42%
4-hour Battery Storage	100%	100%	85%	85%
8-hour Battery Storage	100%	100%	94%	94%

The Companies estimated capacity contributions for battery storage as part of the analysis summarized in Exhibit SAW-1 (see pages D-23 and D-24 of Appendix D). The Companies did not evaluate capacity contributions for battery storage for the 2021 IRP.

f. In the 2021 IRP, the Companies determined target reserve margin ranges as 17 to 24 percent in the summer and 26 to 35 percent in the winter. In the pending application, the Companies determined the minimum reserve margin target as 17 percent in the summer and 24 percent in the winter.

g. As stated in section 3.2 of the Long-Term Resource Planning Analysis in Vol. III of the 2021 IRP, the IRP analysis assumed Mill Creek 2 and Brown 3 would be retired in 2028 based on analysis summarized in Exhibit LEB-2 of Case Nos. 2020-00349 and 2020-00350, and that all remaining CO_2-emitting units would be retired at the end of their book lives. The IRP did not further evaluate the economic retirement of coal units. For the pending application, the Companies evaluated the economic retirements of Mill Creek 2, Ghent 2, and Brown 3 (see section 4.4.1 of Exhibit SAW-1 for PLEXOS modeling assumptions). In doing this, the Companies assumed the remaining existing resources will continue to operate throughout the analysis period to focus the analysis on the decisions at hand (i.e., to determine the most cost-effective way to comply with the Good Neighbor Plan, and evaluate the continued operation of Brown 3 in light of its high operating costs and upcoming need for major maintenance in 2027).

h. See Exhibit SAW-2 at the following location: \06_ModelInputs\CommodityPriceForecasts.

The entire attachment is confidential and provided separately under seal.

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Case No. 2022-00402

Question No. 91

Responding Witness: Tim A. Jones / Stuart A. Wilson

Q-91. Refer to LG&E/KU's 2021 IRP in Case No. 2021-00393.[6] Also refer to the pending application in this case.

a. Confirm that the IRP model did not reflect any IRA provisions, since the IRA was not enacted when the IRP was produced.

b. State whether any anticipated provisions similar to the IRA were reflected in the IRP model, and if so, identify those provisions.

c. Provide a list of all the model inputs that reflect IRA provisions in the pending application

A-91.

a. Confirmed.

b. The IRP did not reflect any provisions similar to the IRA. However, Figure 10 on page 19 of the Jones Direct Testimony shows the 2021 IRP load forecast assumed energy efficiency improvements would continue.

c. IRA provisions primarily impacted the RS and GS forecasts. The EV and Distributed Generation forecasts changed as well. For specific model impacts, see Exh. TAJ-3 at:

- July2022_Forecast\Electric\2_Forecasts\Residential\Work\KU\Data
- July2022_Forecast\Electric\2_Forecasts\Residential\Work\LE\Data
- July2022_Forecast\Electric\2_Forecasts\Residential\Work\ODP\Data
- July2022_Forecast\Electric\2_Forecasts\Commercial\CONFIDENTIAL_Data\EastSouthCentralCom21_AccEff.xlsx
- July2022_Forecast\Electric\2_Forecasts\PV\Input_Data

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[6] Case No. 2021-00393, Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (filed Oct 19, 2021), 2021 IRP.

- July2022_Forecast\Electric\2_Forecasts\EV\Input_Data
- Hourly_Forecast_Updates\ CONFIDENTIAL_tbl10_OvernightCharging_Final_D03.xlsx
- Hourly_Forecast_Updates\DSM\Efficiency_Adjustments_D02.xlsx
- Hourly_Forecast_Updates\DSM\DSM_and_EE_Analysis_D06.xlsx
- Hourly_Forecast_Updates\Space_Heating_Electrification\Heating_Electrification_AdjustmentsD02.xlsx
- Hourly_Forecast_Updates\PV
- Hourly_Forecast_Updates\EV
- Hourly_Forecast_Updates\End_Use_Analysis

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Question No. 92

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-92. Refer to LG&E/KU's 2021 IRP in Case No. 2021-00393, page 5-39 stating that "the current environment does not support the installation of NGCC without CCS due to its CO2 emissions."[7]

a. Explain whether LG&E/KU considered NGCC units with CCS in their current analysis and reconcile this consideration with the IRP statement.

b. Explain why the analysis conducted by LG&E/KU in the 2021 IRP in Case No. 2021-00393 identified SCCTs as the sole type of new gas generation resource addition, whereas the analysis conducted in this application identified NGCC as the sole type of new gas.

A-92.

a. No. No RFP response was received that included an NGCC with CCS. The IRP was a planning exercise to better understand how various technologies would perform (physically and financially) under various alternative futures. This case is about how to address pending EPA regulations and upcoming overhaul costs for Brown Unit 3, and it involves evaluating real proposals received in a competitive RFP. Furthermore, as was demonstrated in the IRP, NGCC without CCS was economically preferred to NGCC with CCS, so it is not surprising that no bidder responded to the RFP with a proposal that included CCS.[60]

b. In the original 2021 IRP filing, NGCC without CCS was not considered an available option and SCCT was least-cost. However, in subsequent discovery the Companies demonstrated that if NGCC does not require CCS, then NGCC would be preferable to SCCT, which is the same conclusion the Companies have reached in the current proceeding.[61]

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[7] Case No. 2021-00393, Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (filed Oct 19, 2021), 2021 IRP at 5-39.
[60] Case No. 2021-00393, Companies' Response to PSC 2-1 (Mar. 25, 2022).
[61] *Id.*

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Question No. 93

Responding Witness: Philip A. Imber / Stuart A. Wilson

Q-93. Refer to the EPA's draft white paper on greenhouse gas emission reduction technologies, issued on April 21, 2022 and titled Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units, in which the EPA explored carbon capture and storage (CCS) as well as hydrogen blending technologies.[8]

a. Provide a timetable for when LG&E/KU expect a final version of the draft white paper to be issued.

b. State whether LG&E/KU believe the EPA will base any rulemaking on New Source Performance Standards for greenhouse gas emissions at new natural gas plants on the EPA's April 2022 white paper (or the final version of that paper), and explain each basis for LG&E/KU's belief.

c. Explain generally the process by which the EPA reviews New Source Performance Standards, including specifically when periodic reviews are required under the current framework.

d. State whether LG&E/KU believe there is a risk that the EPA's current review of New Source Performance Standards for greenhouse gas emissions at new natural gas plants could result in a CCS-based standard, and explain each basis for LG&E/KU's response.

e. Explain whether LG&E/KU's proposed NGCC units were tested against a range of potential revised greenhouse gas New Source Performance Standards for CO2.

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[8] EPA, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units (issued April 21, 2022) (last accessed Feb. 15, 2023) < https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbineegus_draft-april-2022.pdf>.

f. If a CCS-based standard or a standard reducing the existing 1,000 lbs./MWh by 20 to 30 percent were initiated, describe the economic impact on the proposed NGCC plants and explain each basis for LG&E/KU's response.

g. If LG&E/KU do not expect the EPA to adopt New Source Performance Standards that would require, indirectly or otherwise, CCS at new natural gas plants as part of the EPA's current review of New Source Performance Standards, explain each basis for LG&E/KU's expectation and explain whether LG&E/KU expect the EPA to adopt New Source Performance Standards that would require CCS at new natural gas plants (i.e. in 8 years, 16 years, or at some other period), and if so, when.

h. Explain whether LG&E/KU's proposal in this case is based in whole or in part on its desire to begin operating its proposed NGCC units before the EPA adopts New Source Performance Standards that would require CCS on new NGCC units.

A-93.

a. Companies have no basis for an EPA timetable to publish a final report on greenhouse gas reduction technologies.

b. The white paper states the following: **"the information herein may also be useful to EPA in future development of new source performance standards (NSPS), which must be based on the "best system of emission reduction … adequately demonstrated."** See Imber Direct Testimony 6:12. The whitepaper does not contain defensible data to support the achievable and adequately demonstrated hurdles of Clean Air Act Section 111. Dispatchable electric generating units are necessary for the reliability of the electric grid. Implementing new source performance standards on technology that is not achievable or adequately demonstrated would be counterproductive.

c. The EPA issued final NSPS to limit emissions of GHG manifested as carbon dioxide from stationary electric generating units in 2015. According to the Clean Air Act 111(b)1.B: **"The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards. Notwithstanding the requirements of the previous sentence, the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard. Standards of performance or revisions thereof shall become effective upon promulgation."** As such, and as stated in the EPA's Fall 2022 Unified Agenda, the EPA is planning to publish a revised NSPS in 2023 and can revisit the standard at any time in the future.

d. There is a risk that a revised NSPS for greenhouse gas from natural gas plants could be proposed with inclusion of a CCS-based standard. The current coal based NSPS is based on partial CCS. Nonetheless, please refer to Imber Direct Testimony 6:12 for an explanation on the Company position.

e. No.

f. The Companies have not performed this analysis and cannot perform the analysis until EPA sets a standard of performance and best system of emissions reductions. If such a standard is proposed, the Companies will evaluate the specifics of the new standard to determine their impact to the optimal portfolio and potentially revise the plans for retirements and new generation as warranted.

g. The reductions in the NSPS standard for greenhouse gas are not adequately demonstrated. In 2008, the Federal Government implemented a tax credit in the Internal Revenue code, Section 45Q, to provide tax credit incentives for CCUS. In 2022, the Inflation Reduction Act (IRA) revised the tax credit incentives for CCUS. The Companies conclude the government is promoting and offering to financially support demonstration of CCUS through the IRA incentives and other mechanisms like the U.S. Department of Energy grant for work at Cane Run.[62] This process will take years and may align with the construct of a future review of the NSPS in 2031, or sooner, at the discretion of the EPA.

h. This was not a consideration. The Companies' timing of this case is to comply with the Good Neighbor Plan.

[62] For more on the U.S. Department of Energy grant for work at Cane Run, see the response to JI 1-33(a).

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Question No. 94

Responding Witness: Charles R. Schram / Stuart A. Wilson

Q-94. Explain whether LG&E/KU accounted for the "Energy Community Bonus" of the IRA for the solar and storage resources that would replace the coal units. Specifically, explain:

a. Whether there was any communication with RFP respondents about the applicability of the provision;

b. Whether any RFP response was updated based on the inclusion of this bonus; and

c. Whether LG&E/KU included that bonus in their modeling essentially reducing the cost of solar and storage resources beyond the RFP bids. If yes, explain for which projects the bonus credit was available.

A-94. The Companies disagree with the assertion that solar and storage resources would replace the coal units. Mr. Sinclair's testimony on pages 16-17 discusses the Companies' evaluation of generation portfolios, including renewables-only, noting that the Companies' proposed portfolio of two NGCCs, solar, DSM, and BESS, optimizes reliability, cost, and risk. Table 13 on page 32 of Exhibit SAW-1 compares the present value of revenue requirements for the portfolios evaluated across the fuel price and CO_2 price scenarios and demonstrates the favorability of the Companies' proposed portfolio.

a. Some respondents mentioned the potential for the "Energy Community Bonus" in discussions but did not specifically tie pricing to this provision. Also see the response to Question No. 69. The Companies issued a competitive RFP and respondents fully understood the competitive nature of their offers during the follow-up communication regarding potential IRA updates.

b. See the response to Question No. 69.

c. See Section 7.5 in Exhibit SAW-1. For PPAs, the impact of the IRA incentives is reflected in the PPA price. None of the evaluated solar asset projects meet the requirements for the Energy Community Bonus. Battery storage asset projects, on the other hand, are assumed to meet the requirements and receive the maximum ITC afforded by the IRA (50%). See also the response to Question No. 47(a).

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Question No. 95

Responding Witness: Stuart A. Wilson

Q-95. Explain whether energy storage was allowed to dispatch economically or followed a fixed dispatch profile in the SERVM analysis.

A-95. Energy storage was allowed to dispatch economically in the SERVM analysis.

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Question No. 96

Responding Witness: Stuart A. Wilson

Q-96. Provide the book life and operating life used to model the new NGCC resources

A-96. The book and operating life of NGCC resources is 40 years, which is consistent with the depreciation period established for Cane Run 7.

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Question No. 97

Responding Witness: Tim A. Jones

Q-97. Indicate whether IRA tax credits of 30 percent for home battery storage were considered in assumptions around its economics leading to LG&E/KU's decision to model only distributed solar generation.

A-97. See the response to Question No. 35.

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Question No. 98

Responding Witness: Stuart A. Wilson

Q-98. Provide the CO_2 emission rates for the proposed new NGCC units.

A-98. The proposed new NGCC units are expected to have CO_2 emission rates of 119 lbs./MMBtu. This equates to 739 lbs./MWh based on a summer heat rate at maximum operating level.

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Question No. 99

Responding Witness: Lonnie E. Bellar

Q-99. Provide a detailed description of the performance of LG&E/KU's thermal generation fleet during winter storm Uri and winter storm Elliott, including any unplanned outages at its coal or natural gas plants.

A-99. Generation outage data is provided as an attachment.

The attachment is being provided in a separate file.

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Question No. 100

Responding Witness: Lonnie E. Bellar

Q-100. Provide the forced outage rates for each thermal generation unit in LG&E/KU's fleet over the last five years.

A-100.

Forced Outage Rates					
	2018	2019	2020	2021	2022
Brown 1	14.06%	0.00%	-	-	-
Brown 2	4.27%	7.44%	-	-	-
Brown 3	12.49%	6.37%	3.25%	3.16%	5.04%
Ghent 1	1.54%	1.56%	1.20%	2.41%	1.20%
Ghent 2	1.90%	0.68%	0.61%	0.30%	0.66%
Ghent 3	4.86%	0.87%	1.12%	0.98%	0.20%
Ghent 4	1.11%	0.10%	1.97%	0.54%	5.25%
Cane Run 7	0.72%	1.04%	1.60%	0.34%	5.29%
Mill Creek 1	1.16%	2.93%	1.19%	2.56%	1.17%
Mill Creek 2	2.29%	1.80%	0.45%	4.18%	6.69%
Mill Creek 3	1.21%	3.89%	1.19%	1.03%	0.70%
Mill Creek 4	2.41%	0.75%	1.69%	2.85%	0.02%
Trimble County 1	1.88%	3.34%	1.26%	2.59%	3.92%
Trimble County 2	2.73%	7.52%	2.03%	3.01%	2.21%

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 101

Responding Witness: Stuart A. Wilson

Q-101. State what LG&E/KU would expect an ELCC value to be for its proposed NGCC units and explain why.

A-101. If the Companies were in an RTO, they would expect the proposed NGCC units to have an ELCC value of one because those units are fully dispatchable resources.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 102

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-102. State whether there are any naturally occurring, utility scale carbon storage sites in the vicinity of the proposed NGCC units, and provide any written analysis of potential carbon storage sites in LG&E/KU's balancing area.

A-102. The Companies are not aware of any operating carbon storage sites near the proposed NGCC units or any place in Kentucky. The Companies are aware of a 2010 report prepared by the Kentucky Geological Survey and University of Kentucky titled, "Evaluation of Geologic CO_2 Sequestration Potential and CO_2 Enhanced Oil Recovery in Kentucky" located at:

https://kgs.uky.edu/kgsweb/olops/pub/kgs/Energy/RI21_12/RI21_12.htm

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 103

Responding Witness: Philip A. Imber

Q-103. Explain whether there is a risk of an existing source performance standard being implemented that would require, whether directly or indirectly, that CCS be added to LG&E/KU's proposed NGCC units on or before 2050, and if so, explain LG&E/KU's position regarding the likelihood of such a standard being implemented.

A-103. The existing new source performance standard of 1,000 lbs CO_2/MWh does not require CCS. Today, the CCS does not meet the achievable and adequately demonstrated hurdles for new or existing source performance standards. Capture technology needs to be adequately demonstrated. Transport and storage technology needs to be available. Permitting and risk related issues for transport and storage need to be addressed. The government, research entities, and industry are engaged in CCUS research and development. Transformational technologies can change the energy landscape during this period of time. The uncertainty of future CCS prospects is no reason to delay compliance activities for the GNP. See also the response to Question No. 93(g).

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's First Request for Information
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Case No. 2022-00402

Question No. 104

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-104. Identify the interstate natural gas transmission pipeline that serves each of LG&E/KU's existing natural gas units and the interstate transmission pipeline that will serve each of LG&E/KU's proposed NGCC units.

A-104. Texas Gas Transmission serves Can Run 7, Paddy's Run, and the Trimble County SCCTs. Texas Eastern and Tennessee Gas serve the E.W. Brown SCCTs. KU's Haefling small SCCTs are General Sales Other ("GSO") customers of Columbia Gas of Kentucky.

Texas Gas Transmission will serve Mill Creek 12. Tennessee Gas will serve Brown 12 and Texas Eastern will serve as a backup.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 105

Responding Witness: Lonnie E. Bellar

Q-105. Identify each natural gas unit that is currently located in LG&E/KU's balancing area that is operated by an entity other than LG&E/KU that serves load, identify the size of each such unit, identify the operator of each such unit, and identify the interstate transmission pipeline that serves each such unit.

A-105.

- KMPA units owned and operated by Paducah Power
  - Winter Cap. 27mw (4 units)
  - Summer Cap. 25mw (4 units)
  - Texas Gas Pipeline
- Bluegrass units owned and operated by EKPC
  - Winter Cap. 192mw (3 units)
  - Summer Cap. 165mw (3 units)
  - Texas Gas Pipeline

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Case No. 2022-00402

Question No. 106

Responding Witness: Stuart A. Wilson

Q-106. In Excel spreadsheet format, with all formulas, columns, and rows unprotected and fully accessible, provide all workpapers not previously provided.

A-106. To supplement the workpapers previously provided in Exhibit SAW-2, the Companies are providing a copy of the SERVM database backup file. This file is only functional in its native format for use in the SERVM software; therefore it is not being provided in Excel format. It was not provided previously as it is not a standard workpaper, it is very large, and it had not previously been created. But it would be necessary for anyone wanting to see the inputs used directly in the SERVM interface. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The attachments are confidential and provided separately under seal.