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
SUPPLEMENTAL REQUEST FOR INFORMATION
DATED APRIL 14, 2023

FILED: MAY 4, 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 1st day of May 2023.

Caroline J. Dawson

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

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 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.

John Bevington

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

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

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

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

Tammy J. Elzy
Notary Public

Notary Public ID No. KYNP61560

My Commission Expires:

November 9, 2026

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 1st day of May 2023.

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

Tammy J. Elzy

Notary Public

Notary Public ID No. KYNP61560

My Commission Expires:

November 9, 2026

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 2nd day of May 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

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 1st day of May 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

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.

Tim A. Jones

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP 63286

My Commission Expires:

January 22, 2027

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

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 1st day of May 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

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 Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of May 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

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 1st day of May 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP 63286

My Commission Expires:

January 22, 2027

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

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023**

Case No. 2022-00402

Question No. 1

Responding Witness: Philip A. Imber

Q-1. Refer to the Direct Testimony of Philip A. Imber (Imber Testimony), page 4, lines 9–18. Provide the amount of NOx emission allowances for Mill Creek Unit 2 and Ghent 2 from 2022 to 2032 under the current rules and explain whether decreasing allowances would necessitate closing the units irrespective of the Good Neighbor Plan.

A-1. See the response to AG 2-4 for specifics on the final Good Neighbor Plan. The following table depicts the Ghent 2 and Mill Creek 2 NOx ozone-season allocations under the current NOx rule known as Revised CSAPR Update (86 FR 23054, June 29, 2021 effective date):

	GH2	MC2
2022	669	387
2023	669	387
2024 +	669	387

As stand-alone units, the Revised CSAPR Update allocations provided for Ghent Unit 2 and Mill Creek Unit 2 do not support a high unit capacity factor during the ozone season. However, under the Revised CSAPR Update, LKE can surrender banked allocations as well as transfer allocations from units that emit fewer than allocated NOx to compensate for higher Ghent Unit 2 and Mill Creek 2 emissions. The fleet is modeled to comply with the allocations from the Revised CSAPR Update without the need to retire Ghent Unit 2 and Mill Creek Unit 2. Ghent Unit 2 and Mill Creek Unit 2 would need to add controls or retire under the Revised CSAPR Update if allocations were not available through overcontrol of other units in the fleet.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 2

Responding Witness: Stuart A. Wilson

Q-2. Refer to Imber Testimony, page 9, lines 6-10. Also refer also to LG&E/KU's response to Commission Staff's First Request for Information (Staff's First Request), Item 25.

a. Explain how the future natural gas price volatility has been included in the PLEXOS and PROSYM stage modeling when the mid gas price and mid coal to gas price ratio was used.

b. Identify each step of the resource assessment, including the PLEXOS and PROSYM modeling, at which a 250 MW simple cycle combustion turbine (SCCT) was made available as possible resource and explain how the SCCT was made available.

c. In the event there are CO2 emission requirements, explain how much CO2 LG&E/KU estimate would be reduced in each of the CO2 pricing scenarios and whether the reductions, if any, are meaningful.

A-2. Note that all references to Exhibit SAW-1 herein and throughout the Companies' responses are to the updated May 2023 Exhibit SAW-1 provided in response to JI 2-60(a).

a. The Companies' PLEXOS and PROSYM modeling evaluated resource alternatives over a range of fuel price scenarios (low, mid, and high) with the mid coal-to-gas ratio, which is the average ratio of coal and natural gas prices from 2012 to 2021 (see Section 7.7.1 in Exhibit SAW-1 beginning at page 55). In addition, the Companies evaluated low, high, and "current" coal-to-gas price ratios to evaluate the impact of potential changes to this ratio. Moving forward, the level of coal and natural gas prices will undoubtedly vary within a range, and the ratio of coal and natural gas prices will undoubtedly vary about a long-term average. The Companies' focus on a range of fuel price scenarios and a range of long-term average coal-to-gas ratios is appropriate for evaluating long-term resource decisions. For the purposes of this long-term analysis, modeling short-term variations about the long-term average coal-to-gas ratio is not necessary. See Sections 4.4 and 4.5 in Exhibit SAW-1 beginning at page 22 for further information regarding the Companies' analysis.

b. The Companies evaluated two SCCT proposals, one to construct two 250 MW SCCTs at the Mill Creek Station and one to construct two 250 MW SCCTs at the E.W. Brown Station.[1] SCCTs were made available for all portfolios in Stage One, Step One in PLEXOS, and for all portfolios except Portfolio 8 (the All Renewables portfolio) in Stage Two, Step One in PLEXOS. The only portfolio in which SCCT was selected by PLEXOS was Portfolio 9, and the Companies included SCCTs in Portfolio 9 as part of Stage Two, Step Two in PROSYM.

c. As shown in Table 14 of Exhibit SAW-1, the annual CO_2 reductions would range from 0.1 million short tons in the portfolios with large amounts of renewables (Portfolios 8 and 9) to 0.5 million short tons in the economically optimal portfolio with 2 NGCCs (Portfolio 1). Whether or not these reductions are meaningful is subjective, but CO_2 emissions in Portfolio 1 are approximately two percent lower in CO_2 pricing scenarios. The larger CO_2 reduction differences in Table 14 are driven by technology choice and not by CO_2 prices that may eventuate after a technology is chosen. In 2030, CO_2 emissions for the recommended portfolio (Portfolio 1) are 6 to 19 percent lower than the other portfolios regardless of CO_2 price.

[1] The Companies did not receive a single-SCCT proposal in response to their June 2022 request for proposals.

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 3

Responding Witness: Christopher M. Garrett

Q-3. Refer to the Direct Testimony of Robert M. Conroy, page 3. Provide the estimated difference between allowance for funds used during construction using the methodology approved by the Federal Energy Regulatory Commission and LG&E/KU's full-weighted average cost of capital. Provide any supporting calculation in Excel spreadsheet format, with all formulas, columns, and rows unprotected and fully accessible.

A-3. See attachment being provided in Excel format. The difference between the two methodologies is highlighted in gray in the Excel workbook.

The attachment is being provided in a separate file.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 4

Responding Witness: Tim A. Jones / David S. Sinclair

Q-4. Refer to the Direct Testimony of Tim A. Jones, Exhibit TAJ-1, pages 26 and 29, regarding solar adoption by LG&E/KU customers. Also refer to Exhibit TAJ-1, page 26, regarding distributed battery energy storage system installations, which represent "less than 8% of the Companies' total 3,116 distributed generation customers."

a. Explain why the adoption and modeling of battery energy storage should be different than that of solar.

b. Indicate what percentage of distributed generation that battery storage would need to represent to justify incorporating into load forecasting.

A-4.

a. Customers' adoption of distributed battery energy storage *has been and is* different than that of solar: to the best of the Companies' knowledge and information,[2] their customers have installed almost 45 MW of distributed solar capacity and less than 2 MW of distributed battery energy storage.[3] By way of recent data, since October 2022 (shortly after the Inflation Reduction Act took effect) the Companies' customers added 10.21 MW of distributed solar capacity and just 0.16 MW of distributed battery energy storage. The Companies assume the greater than 22-to-1 adoption of distributed solar over distributed battery energy storage (and almost 64-to-1 adoption since October) indicates that customers find the economics of distributed solar to be superior to those of distributed battery energy storage.

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[2] The Companies are aware of customers' distributed battery energy storage only for customers seeking or taking net metering service. It is possible that other customers have distributed battery energy storage without the Companies' knowledge.
[3] *See, e.g.,* the Companies' response to Question No. 78.

Regarding "why the … modeling of battery energy storage should be different than that of solar," they are different technologies with different characteristics for load forecasting purposes:

- Distributed solar generation produces electricity, and it does so relatively predictably: when sunlight can reach the panels and the necessary equipment is properly functioning, distributed solar will produce electricity, reducing instantaneous load and total energy requirements.

- Distributed battery energy storage, on the other hand, never produces electricity; rather, it consumes energy—typically 10% to 20% of input energy is lost in the AC-DC-AC conversion and storage and discharge processes—and moves energy consumption in time, i.e., it consumes energy at one time and discharges it at a later time. Therefore, it increases total energy requirements. But when and to what extent distributed energy storage will consume and discharge energy is highly dependent on rate design, particularly the price difference between on- and off-peak periods and the hours that make up those periods. Batteries that customers use primarily or exclusively as backup energy systems will have little or no offsetting effect on system demand precisely because their purpose is to discharge when affected customers are not connected the grid, and there are alternative back-up generation technologies that have better technical and economic performance for many applications (e.g., fossil-fuel fired back-up generators). Batteries that customers use primarily to store lower cost energy to be consumed in higher-rate periods are somewhat more predictable based on rate structures, but it is unknown how many customers will use batteries primarily as backup systems, primarily as rate arbitrage devices, or as a hybrid (i.e., holding back some amount of charge at all times for backup energy with the rest available to obtain energy cost savings through rate arbitrage).

At this time, there is too little data upon which to model distributed battery energy storage adoption rates or load impacts for the Companies' customers with any reasonable degree of confidence.

Furthermore, it is notable that the vast majority of the Companies' customers take service under rate schedules with a single, non-time-differentiated energy rate and no demand charge (i.e., Rates RS and GS). For such customers (who are not also net metering customers), there is no financial incentive to add distributed battery energy storage. Any such customers who did add distributed battery energy storage presumably would do so only as energy backup, which would have no effect on the Companies' load forecast.

Relatedly, it is also noteworthy that few RS or GS customers have pursued optional time-of-day rates with time-differentiated energy or demand charges (roughly 220 RTOD-Energy customers, eight RTOD-Demand customers, one GTOD-Energy customer, and zero GTOD-Demand customers). Particularly given that RTOD rates have been available since mid-2015 (GTOD rates have been available since mid-2021), customers' lack of interest in those rates suggests that they do not believe they could achieve savings by adding distributed battery energy storage and switching to time-of-day rates.

Finally, it is telling that of the Companies' NMS-2 customers on Rates RS and GS, who effectively have two energy rates (an energy consumption rate and an energy compensation rate), only a small fraction of those have elected to add distributed battery energy storage and *none* of those who have added batteries are currently taking service under an optional time-of-day rate. Thus, it appears that the economics of distributed solar with distributed battery energy storage are not overwhelmingly attractive overall, and it appears that time-of-day rates do not improve the economics of battery energy storage.

b. There is not a particular "percentage of distributed generation that battery storage would need to represent to justify incorporating into load forecasting." By way of context, the Companies individually forecast only around 30 customer loads due to their demands. The lowest peak demand for such customers in 2028 is around 8 MW. If customers continued to add distributed battery energy storage at the same five-month growth rate that occurred between October 2022 and March 2023, by the beginning of 2028 there would be approximately 5.51 MW of distributed battery energy storage on the Companies' system.[4] Therefore, there is currently little, if any, reason to expect that distributed battery energy storage will have any noticeable impact on customers' aggregate demand or the Companies' ability to reliably serve customers' needs by 2028.

[4] Between October 2022 and March 2023, distributed battery energy storage of which the Companies are aware (because the customers are net metering customers) grew from 1.62 MW to 1.78 MW, a five-month increase of 9.88%. Assuming the same rate of growth for the next five years results in distributed battery energy storage of 5.51 MW in early 2028 ($1.78 * 1.0988^{12} = 5.51$).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 5

Responding Witness: Robert M. Conroy / Charles R. Schram

Q-5. Refer to the Direct Testimony of Stuart A. Wilson, (Wilson Testimony) Exhibit SAW-1, 2022 Resource Assessment, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, Footnote 9, page D-10 referencing the 125 MW Ragland solar facility.

a. Identify the location of the facility and the developer/owner.

b. State when LG&E/KU expects the solar facility developer/owner to file a notification of the application with Kentucky State Board on Electric Generation and Transmission Siting (Siting Board).

c. Provide a copy of the solar facility power purchase agreement between LG&E/KU and the solar facility developer/owner or, if the power purchase agreement has not been executed, the status of the pending agreement.

A-5.

a. The Ragland solar facility is being developed by BrightNight LLC in McCracken County, Kentucky. The Companies executed the Ragland PPA to serve five customers in accordance with the Companies' Green Tariff Option 3. All energy from the Ragland facility will be purchased by those customers in accordance with their Renewable Power Agreements ("RPAs").

b. The developer anticipates filing a notification of application with the Siting Board in October 2023.

c. The referenced power purchase agreement was filed with the Commission through the tariff filing of the special contract RPAs in TFS2021-00414 (KU special contract RPAs) and TFS2021-00415 (LG&E special contract RPAs). Links to the document are below.

https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/11032021023612/KU_414_LGE_415_PPA.pdf https://psc.ky.gov/trf4/uploadedFiles/500_Louisville_Gas_and_Electric_Company/11032021023717/KU_414_LGE_415_PPA.pdf

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 6

Responding Witness: Lonnie E. Bellar

Q-6. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 46. Provide a copy of the most current agreement between LG&E and Louisville Air Pollution Control Board regarding limiting the operation of the Mill Creek Station in order to address the Louisville/Jefferson County ozone requirements for ozone seasons. Additionally, explain the circumstances that led to the agreement, the term of the agreement, and the remedies if LG&E were to violate the agreement.

A-6. See attached.

LG&E entered into the first enforceable board agreement in 2020 and updated it in 2021 and 2022. The Louisville Metropolitan Statistical Area (MSA) was designated non-attainment for the 2015 ozone National Ambient Air Standards in April of 2018. District Regulation 3.01 Section 4 prohibits the emissions of an air contaminant that would violate or interfere with the attainment or maintenance of an ambient air quality standard. Ozone is a resultant of a chemical reaction between NOx and volatile organic compounds. Mill Creek is the largest single point source of NOx in Jefferson County. LG&E agreed to take measures to reduce NOx at Mill Creek consistent with the objectives of District Regulation 3.01. LG&E was awarded Platinum Level status in the Louisville Metro Air Quality Action Partner Program two years in a row because of this agreement.

The current agreement sunsets upon the retirement of either Unit 1 or Unit 2.

The agreement does not stipulate specific remedies for violation of the agreement terms.

LG&E has not violated the terms of the agreement.

The attachment is being provided in a separate file.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 7

Responding Witness: Lana Isaacson / Stuart A. Wilson

Q-7. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 14, Table 2.

a. Explain why there is an increase for the Peak Time Rebates 2029 fixed costs considering the costs are trending to decrease every year.

b. Explain further what the LG&E/KU mean by "summer capacity values are design-day values" when discussing the DLC-AC in footnote 7.

A-7.

a. The increase in the 2029 fixed cost for the Peak Time Rebates program reflects an estimated EM&V review of the program in 2029.

b. The capacity values shown in the referenced table reflect more extreme "design-day" weather conditions and not "normal" or average peak day weather conditions. Load reductions for the DLC-AC program are higher under more extreme temperatures because air conditioners cycle off less frequently under these conditions.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 8

Responding Witness: Stuart A. Wilson

Q-8. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 22, Table 4. Explain why avoided costs were not used in the fuel-price scenarios given that avoided costs include the avoided fuel, operations, and maintenance costs of a power plant.

A-8. The Companies disagree with the premise in the data request that relevant costs were not included in this analysis. The Companies' analysis includes all costs that contribute to customer revenue requirements. Table 4 in Exhibit SAW-1 provides a description of general categories of cost in the Financial Model. Fuel and variable operating costs are included in Generation Production Costs. Maintenance costs are included in Stay-Open Costs. Avoided costs can be assessed by comparing the total costs of two portfolios.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 9

Responding Witness: Stuart A. Wilson

Q-9. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 22–23, discussing Stage One, Step One of the resource assessment.

a. Confirm that in the PLEXOS model there is no direct connection between the decision to retire a coal resource and the decision to build a natural gas combined cycle (NGCC) resource. If not confirmed, describe any and all constraints that directly connect the decisions and provide any documentation supporting these assumptions.

b. Provide the net present value revenue requirement (NPVRR) and CO2 emissions associated with each model run.

A-9.

a. Confirmed. When the PLEXOS model decides to retire a coal resource or build an NGCC, it is doing so to minimize PVRR *while still meeting reliability constraints*. Although there are no constraints that directly tie coal resource retirement decisions to building an NGCC resource, the model does retire coal resources as a direct result of them being more expensive on a PVRR basis than a new NGCC resource.

b. See attachment being provided in Excel format. Each of the six Fuel Price Scenario rows in the attached file ties to the corresponding Fuel Price Scenario row in Table 5 of Exhibit SAW-1.

The attachment is being provided in a separate file.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 10

Responding Witness: Stuart A. Wilson

Q-10. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 22–23, discussing Stage One, Step One of the resource assessment.

a. Provide an exhaustive list of all resources that are available to be selected in Stage One, Step One.

b. State whether the decision to install selective catalytic reduction system (SCR) is reflected in the model by a new resource with the same characteristics as the coal unit that also has SCR.

c. State whether the decision to retire a coal unit is reflected in the model by the selection of a resource with the same characteristics as the coal unit and a termination date equal to the retirement. If yes, please provide a list of all resources available for selection.

d. Explain whether the proposed battery energy storage system at E.W. Brown (Brown BESS) resource is available for selection.

e. Explain in detail the constraints. If this list is not exhaustive, provide information on any missing constraint that the selection of new resources is subject to:

(1) NewGas_MC;
(2) NewGas_MCbeforeBR_CC;
(3) NewGas_MCbeforeBR_CT;
(4) ExclusiveProjectsStorage_Projects_XX (where XX are the different projects per the Companies' nomenclature);
(5) Solar+StorageOption_XX; and
(6) Solar+StorageOnly_XX.

A-10.

a. See Tables 42 and 44 in Exhibit SAW-1 Appendix B.

b. No. The Companies modeled Ghent 2 and Mill Creek 2 in PLEXOS with the assumption that SCR will be added to the units unless they retire, not as new replacement units with SCR. If the units do not retire in PLEXOS, the cost of SCR is incurred and the characteristics of the unit change to reflect the SCR's operation.

c. No. The units for which retirement is being considered in the model are specified so that PLEXOS can directly choose to retire the unit (using PLEXOS's "Max Units Retired" property).

d. No, the Brown BESS was not available for selection in the Stage One or Stage Two analyses.

e.

(1) NewGas_MC: This constraint stipulates that the model cannot build both NGCC and SCCT at Mill Creek.

(2) NewGas_MCbeforeBR_CC: This constraint stipulates that the model may not build an NGCC at Brown without building either an NGCC or two SCCTs at Mill Creek. See the response to Question No. 15(c).

(3) NewGas_MCbeforeBR_CT: This constraint stipulates that the model may not build SCCTs at Brown without building either an NGCC or two SCCTs at Mill Creek. See the response to Question No. 15(c).

(4) ExclusiveProjectsStorage_Projects_XX: Some companies participating in the Companies' 2022 RFP (Request for Proposal) provided battery storage proposals with multiple variants from which only one was available for selection. Each variant was added to PLEXOS as a separate unit (For example, 10a-B, 10b-B & 10c-B) and this constraint prevented PLEXOS for selecting more than one of them.

(5) Solar+StorageOption_XX: Some companies participating in the Companies' 2022 RFP process provided solar generation proposals with the option to add battery storage. The battery storage options these companies offered were not available without also selecting the solar generation proposal. This constraint gives PLEXOS the option to choose either the solar-only option or the solar+storage option, but not the battery storage alone.

(6) Solar+StorageOnly_XX: Some companies participating in the Companies' 2022 RFP process provided proposals for solar generation paired with battery storage, although neither the battery nor the solar option were offered individually. This constraint requires PLEXOS to build both the solar and battery associated with these proposals instead of selecting the solar or battery individually.

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**Response to Commission Staff's Supplemental Request for Information
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Case No. 2022-00402

Question No. 11

Responding Witness: Stuart A. Wilson

Q-11. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 22-24, 27-31 discussing Stage One, Step One and Stage Two, Step One of the resource assessment. Refer also to the Excel file titled CONFIDENTIAL_20221212_Combined_Solution_Views_2061-2073.xlsx (PLEXOS outputs) filed with the Joint Application.

a. Provide a list of portfolios generated in Stage One, Step One, and identify which "Run_ID" on the "Index" tab of the referenced spreadsheet corresponds to each portfolio.

b. Provide a list of portfolios generated in Stage Two, Step One, and identify which "Run_ID" on the "Index" tab of the referenced spreadsheet corresponds to each portfolio.

c. Provide a detailed description of any other PLEXOS runs that were conducted but not referenced directly in the Resource Assessment and explain the reason for conducting any such runs.

A-11.

a.

Portfolio Name	Run_ID
Low Gas, Mid CTG Ratio	2061
Mid Gas, Mid CTG Ratio	2062
High Gas, Mid CTG Ratio	2063
Low Gas, High CTG Ratio	2064
High Gas, Low CTG Ratio	2065
High Gas, Current CTG Ratio	2066

b.

PortNum	Portfolio Name	Run_ID
1	MC5 & BR12	See note i below
2	MC5/GH2 SCR	See note i below
3	MC5;Non-Ozone GH2	2067
4	MC5;Non-Ozone GH2Retire BR3	2068
5	MC2/GH2 SCR	2069
6	Non-OzoneMC2/GH2	2070
7	Non-Ozone MC2/GH2; Retire BR3	2071
8	All Renewables	2072
9	SCCT + Renewables	2073
10	DSM Only	See note ii below

i. Portfolios 1 and 2 were carried forward from the Stage One analysis, which included the PLEXOS Run_IDs listed in the response to part (a).
ii. Portfolio 10 was not derived from a PLEXOS model run because it would be impossible for the model to produce a portfolio that meets summer and winter reserve margin with only DSM resources available.

c. The PLEXOS runs referenced in the Resource Assessment were the result of an iterative process whereby models were developed and repeatedly run as new information became available throughout the Companies' RFP process. Outside of these preliminary and incomplete model iterations, no other PLEXOS model runs informed the Companies' Resource Assessment analysis.

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Response to Commission Staff's Supplemental Request for Information
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Case No. 2022-00402

Question No. 12

Responding Witness: Stuart A. Wilson

Q-12. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 23, Table 5. Explain the reasoning behind excluding dispatchable Demand Side Management (DSM) programs from the Stage One portfolio and then adding them back later in the process.

A-12. Dispatchable DSM programs were excluded from the Stage One portfolios because they were not selected by PLEXOS as part of the least-cost portfolios. They were included in the Stage Three analysis because the Stage Three analysis was focused, among other things, on fine-tuning the economically optimal portfolio to add reliability to the extent it would be cost-effective to do so.

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Case No. 2022-00402

Question No. 13

Responding Witness: Stuart A. Wilson

Q-13. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 24-26, discussing Stage One, Step Two of the resource assessment.

a. Confirm that this step is a production cost modeling step.

b. Confirm that the portfolios generated for analysis in this step were not generated through optimization.

c. Provide the NPVRR and CO_2 emissions associated with each model run.

A-13.

a. Confirmed.

b. Confirmed. The portfolios in this step were developed based on the results of the Stage One, Step One screening analysis. The purpose of this step was to use detailed production cost modeling to determine an optimal portfolio over a range of fuel price scenarios.

c. See attachment being provided in Excel format.

The attachment is being provided in a separate file.

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Question No. 14

Responding Witness: Stuart A. Wilson

Q-14. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 26, footnote 13. Provide any workpapers or analysis supporting the claim that "the optimal amount of solar over the fuel price scenarios with a Mid coal-to-gas price ratio is also 637 MW."

A-14. See the ModelCounterPivot tab of "\04_FinancialModel\CONFIDENTIAL_20221209_FinancialModel_0308_Ph1_D01.xlsx" in Exhibit SAW-2. Cells B6 through X12 show the PVRR for the six fuel price scenarios (column B) and the eleven solar PPA scenarios (a) with Ghent 2 retired (columns C though M) and (b) with Ghent 2 continuing to operate (columns N through X). Row 13 shows the average of the fuel price scenarios with a Mid coal-to-gas ratio, with the lowest cost portfolio E05 (pertaining to 637 MW) highlighted in red.

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Question No. 15

Responding Witness: Stuart A. Wilson

Q-15. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 28, Table 10.

a. Confirm that Brown Unit 3 is overhauled in Portfolio 3.

b. Confirm that the decision to overhaul Brown Unit 3 is made exogenously for Portfolio 3. If not confirmed, list any constraints in the model that are related to the resource decision for Brown Unit 3 in Portfolio 3.

c. For portfolios that add a single NGCC unit, Portfolio 2, Portfolio 3, and Portfolio 4, confirm that the decision to build Mill Creek NGCC rather than Brown NGCC was made exogenously.

(1) If confirmed, provide your reasoning for that decision with respect to each of the three portfolios.

(2) If not confirmed, list all constraints in the model that are related to the selection of the NGCC resources.

d. Explain why none of the portfolios developed for stress testing add one NGCC while retiring all three coal units.

A-15.

a. Confirmed.

b. Confirmed.

c. Confirmed. If the Companies receive approval for only one NGCC, it needs to be constructed at the Mill Creek Station so that Brown 3 can remain available to support reliability until all resources needed for Good Neighbor Plan compliance are in place. This is the primary reason why the Brown NGCC (Brown 12) is commissioned after the Mill Creek NGCC (Mill Creek

5) in the proposed portfolio with two NGCCs. Furthermore, the Companies cannot construct Brown 12 until 2028 (after they have demolished Brown 1 and 2). Brown 3 and Brown 12 will not be able to operate simultaneously after Brown 12 is commissioned due to transmission system limitations.

d. The Stage Two portfolios were developed in part to consider a wide range of perspectives regarding what the Companies' optimal resource mix should be. The Companies did not anticipate a perspective that would favor the referenced portfolio. The referenced portfolio and numerous other portfolios that could have been included in the Stage Two analysis were evaluated in the Stage One, Step One screening analysis using PLEXOS and not selected as least-cost.

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Question No. 16

Responding Witness: Stuart A. Wilson

Q-16. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 28, Table 10. Explain why dispatchable DSM was not included in every scenario.

A-16. Dispatchable DSM is not referenced in the description of Portfolios 1 and 2 because these portfolios were simply carried over from the Stage One analysis where dispatchable DSM was not selected as part of a least-cost portfolio. As seen in Portfolios 1 and 2, the optimal amount of solar and dispatchable DSM is not materially impacted by whether the coal units are retired and replaced with NGCC (see support for this statement in the response to Question No. 14). Portfolio 5 has the same amount of solar and dispatchable DSM as Portfolios 1 and 2 for this reason. For Portfolios 3, 4, and 6-9, dispatchable DSM was included as an available resource in PLEXOS.

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Question No. 17

Responding Witness: Stuart A. Wilson

Q-17. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 27-31 discussing Stage Two, Step One of the resource assessment.

a. Confirm that this included a capacity expansion modeling step.

b. Provide the NPVRR and CO2 emissions associated with each model run.

c. Confirm that the solar Purchase Power Agreement (PPA) start dates in Stage Two, Step One were not limited to the actual start dates of the PPAs as proposed in responses to the RFP.

d. Provide a list of all of the resource decisions that were made exogenously for each of the portfolios generated in Stage Two, Step One.

A-17.

a. Confirmed. See Exhibit SAW-1 at the bottom of page 28.

b. See attachment being provided in Excel format for requested data on Stage Two, Step One Portfolio Numbers 3-9. The attachment does not contain data on the model runs for Portfolio Numbers 1-2 and 10 for the reasons noted under the table included in response to Question No. 11(b).

The Stage Two, Step One results differ from the Stage Two, Step Two results for several reasons.

- The PLEXOS results reflect the direct output of the model in 2026 dollars, which is "year 0" for the modeled study period starting in 2027, which is four years shorter than the Stage Two, Step Two study period starting in 2023.
- In Stage Two, Step One, PLEXOS was also allowed to choose RFP options throughout the study period if they were economic in later years; only resources selected by 2028 in PLEXOS were modeled in PROSYM based on their RFP-specified contract terms.

- Stage Two, Step One did not include the revenue requirements associated with the sunk costs of prior investments for the Companies existing units, which were included in the total NPVRR for all portfolios in Stage Two, Step Two, but resulting in no incremental NPVRR.

c. Confirmed. The amount of PPAs included in each portfolio is the amount added by 2028.

d. The table below describes resource decisions made exogenously for each portfolio in Stage Two, Step One of the Resource Assessment.

Decision	**Portfolios Affected**
Add optimal portfolio of renewables, battery storage, and dispatchable DSM	3, 4, 6 - 9
Add same amount of renewables and dispatchable DSM as Portfolios 1 and 2	5
Operate GH2 in non-ozone season only	3, 4, 6, 7
Operate MC2 in non-ozone season only	6, 7
Add SCR at GH2 and MC2	5
Complete BR3 overhaul	3, 5, 6
Retire BR3	4, 7
Retire MC2, BR3, and GH2	8, 9
Disallow new non-renewable resources	5 - 8
No coal retirements	5, 6
No SCRs	6, 7

The attachment is being provided in a separate file.

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Response to Commission Staff's Supplemental Request for Information
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Question No. 18

Responding Witness: Stuart A. Wilson

Q-18. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 31–33 discussing Stage Two, Step Two of the resource assessment.

a. Confirm that this step is a production cost modeling step.

b. Provide the NPVRR and CO2 emissions associated with each model run.

c. Confirm that for Portfolios 1, 2, and 5, all the selected solar PPAs are modeled with the start dates proposed in their associated RFP responses. If not confirmed, please explain how the start dates are modeled.

d. Confirm that for Portfolios 3, 4, and 6–9, the selected solar PPAs are modeled as beginning at the beginning of the year as shown in the "Summary" tab of the Excel file titled CONFIDENTIAL_20221212_Combined_Solution_Views_2061-2073.xlsx. If not confirmed, explain how the start dates are modeled.

A-18.

a. Confirmed.

b. See attachment being provided in Excel format.

c. Confirmed.

d. Not confirmed. In Stage Two, Step Two, the PPAs selected by 2028 in PLEXOS are modeled in PROSYM with the start dates proposed in their associated RFP responses. This is the same approach used in Stage One, Step Two.

The attachment is being provided in a separate file.

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Question No. 19

Responding Witness: Stuart A. Wilson

Q-19. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 34–36, discussing Stage Three, Step One of the resource assessment.

a. Confirm that this step is a production cost modeling step.

b. Confirm that the portfolios generated for analysis in this step were not generated through optimization.

c. Provide the NPVRR and CO2 emissions associated with each model run.

A-19.

a. Confirmed.

b. Confirmed.

c. See attachment being provided in Excel format.

The attachment is being provided in a separate file.

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Response to Commission Staff's Supplemental Request for Information
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Case No. 2022-00402

Question No. 20

Responding Witness: Stuart A. Wilson

Q-20. Refer to the Wilson Testimony, Exhibit SAW-1, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, page D-10, Table 2. Explain why existing DSM was excluded from the Intermittent/Limited-Duration Resources.

A-20. Existing DSM was not excluded. "Existing DLC" in Table 2 represents existing dispatchable DSM programs. The Companies account for the effects of non-dispatchable DSM-EE programs in their load forecast.

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Question No. 21

Responding Witness: Lana Isaacson / Stuart A. Wilson

Q-21. Refer to the Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, page D-18. Refer also to Direct Testimony of Lana Isaacson (Isaacson Testimony). Exhibit LI-6 – CONFIDENTIAL LAK_AvoidedCapacityCost, page 6, Table 7.

a. For the PLEXOS and PROSYM modeling runs, state which avoided capacity capital cost was used, the SCCT capital cost in the Reserve Margin Analysis or the SCCT capital cost used in the DSM analysis. Explain why different avoided cost estimates were used in the analyses.

b. Explain why 2022 dollars are used for the DSM/EE portfolio and 2028 dollars for the minimum reserve margin. Include in the explanation whether the SCCT in 2022 dollars is the discounted amount from the 2028 amount.

c. Regarding LG&E/KU's assumptions for the cost of new capacity, explain why the avoided capacity values are reasonable. Provide and describe in specific detail how LG&E/KU defined a typical installations.

d. Refer also LG&E/KU's response to Staff's First Request for Information, Item 1 to Case No. 2022-00395.[5] LG&E/KU used the capital costs of a SCCT as the basis for avoided costs in their 2021 integrated resource plan (IRP),[6] but used the capital costs of a NGCC as the basis for avoided costs in Case No. 2022-00395. Given that LG&E/KU requests approval of a certificate of public convenience and necessity (CPCN) for two NGCCs in this proceeding, reconcile LG&E/KU's use of different bases for avoided costs in Case Nos. 2022-00395 and 2021-00393 and this case. Also, explain why the capital and

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[5] See Case No. 2022-00395, Electronic Tariff Filing Of Kentucky Utilities Company for Approval of An Economic Development Rider Special Contract With Kruger Packaging, Companies' Response To Staff's First Request for Information, (filed Dec. 22, 2022), Item 1.

[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).

related costs of a NGCC should not be used in the DSM and reserve margin studies in this proceeding.

e. Explain whether the cost-effectiveness of the proposed DSM/EE programs would increase if LG&E/KU were to base their avoided costs on an NGCC instead of an SCCT.

A-21.

a. Only RFP responses and their associated costs were evaluated in PLEXOS and PROSYM. The cost of new SCCT capacity used in the Reserve Margin Analysis is based on an RFP response.[7] The avoided capacity costs for DSM summarized in the "CONFIDENTIAL_LAK_AvoidedCapacityCost" report are computed based on SCCT and NGCC cost estimates from the National Renewable Energy Laboratory's 2021 Annual Technology Baseline ("2021 NREL ATB"). The avoided capacity costs in this report were not used in the DSM analysis. Instead, the DSM analysis utilized the levelized cost of a SCCT installed in 2028 as the avoided capacity cost for DSM programs, and the basis for this cost was also the 2021 NREL ATB. The 2021 NREL ATB was the most recent source of generation costs when the DSM analysis began. See attached for a table comparing SCCT and NGCC costs from the 2021 NREL ATB and the RFP. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The RFP cost estimates are lower primarily because they are prepared for existing sites where opportunities exist to share existing infrastructure.

b. Table 7 in the "CONFIDENTIAL LAK_AvoidedCapacityCost" report lists costs from the 2021 NREL ATB for SCCT and NGCC installed in 2022. However, the avoided capacity cost used in the DSM analysis was the levelized cost of a SCCT installed in 2028. The Reserve Margin Analysis focused on 2028 costs because 2028 was the study year. See Section 4.1 on page D-11 of the Reserve Margin Analysis.

c. See the response to part (a). The 2021 NREL ATB was the most recent source of generation costs when the DSM analysis began.

d. This request highlights the importance of timing and context in choosing appropriate avoided capital costs. Although it is unclear to which *avoided* cost the request intends to refer regarding "SCCT as the basis for avoided costs in their [the Companies'] 2021 integrated resource plan (IRP)," it is correct that the Companies' IRP modeling indicated that, based on 2021 NREL ATB data and assuming NGCC units would require carbon capture and storage ("CCS") technology to comply with carbon constraints, SCCT

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[7] See Response No. 108 in Table 42 in Appendix B of Exhibit SAW-1.

and solar would be the primary technologies deployed to replace retired fossil fuel-fired capacity and meet customers energy needs in a least-cost manner in 2036.[8] The Companies' modeling in the same proceeding showed that including NGCC without CCS as a resource option results in NGCC being the economically preferred resource.[9] But due to the timing and nature of that proceeding, the Companies did not have actual RFP results to use in their IRP resource modeling.

In Case No. 2022-00395, the Companies submitted a proposed EDR contract for approval. In support of the contract and in accordance with Commission requirements for such contracts, the Companies submitted a marginal cost study to demonstrate that the projected revenues from the EDR contract customer would exceed the marginal cost of serving the customer. Two factors are important and relevant to this request in conducting a marginal cost study of that kind: first, customers tend to use energy at a variety of times, not just on peak; therefore, to account most accurately for the marginal production demand cost of a customer, the preferred marginal generating unit for comparison is the likely next non-peaking generating unit, such as an NGCC unit. Second, in the months leading to August 2022 when the Companies' consultant conducted the marginal cost study, it was consistent with the results of the Companies' analysis in the IRP proceeding demonstrating that NGCC was superior to SCCT when NGCC does not require CCS, to analyze NGCC as the likely technology for the Companies' next generating unit, particularly considering that the need for the next generating unit would result from retiring coal-fired units that provide around-the-clock energy.

The timing and results of the Companies' resource analysis in this proceeding are already in the record at length. Suffice it to say that there are two significant differences between the 2021 IRP analysis and the marginal cost study in Case No. 2022-00395 that result from the timing and nature of the proceedings: (1) the Companies' analysis supporting their application in this proceeding included RFP results for actual options on offer for deployment by 2028, not generic projected technology costs from NREL Annual Technology Baselines (which is the most reasonable data to use when fresh RFP data is unavailable); and (2) due to anticipated economic unit retirements, the analysis in this case focuses on a specific, defined need for capacity to allow the Companies to provide reliable, low-cost service beginning in 2028. The clear results of the Companies' analysis are that on every reasonable projection about the future, if the objective is to provide reliable, low-cost service, the Companies' next generating unit will be NGCC.

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[8] *See, e.g., Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, IRP Vol. I at 8-1 (Oct. 29, 2021).
[9] Case No. 2021-00393, Companies' Response to PSC 2-1 (Mar. 25, 2022).

But that clear conclusion does not mean that the appropriate avoided capacity cost for all DSM-EE programs is NGCC. Dispatchable DSM programs are by their nature essentially substitutes for very limited peaking units; they are not designed as round-the-clock energy substitutes. Rather, their purpose is to help reduce load at times of peak demand. Therefore, regardless of what the Companies' next non-peaking unit might be, the appropriate basis of avoided costs for dispatchable DSM programs is unambiguously avoided *peaking* capacity cost, making SCCT cost an appropriate basis of comparison. At the time the Companies' consultant began performing DSM-EE cost-benefit analyses in anticipation of this case, the Companies' RFP results were not available, so it was appropriate to use NREL ATB data for SCCT technology as the basis for avoided capacity cost. Notably, those capacity costs are *higher* than the SCCT RFP responses, effectively favoring dispatchable DSM.

Although there are grounds for suggesting that NGCC would be an appropriate basis for avoided capacity cost for *non-dispatchable* DSM-EE programs, Cadmus's use of NREL ATB SCCT cost as the basis for the avoided capacity cost in the cost-benefit analysis actually favored the programs. See the response to Question No. 38.

e. See the response to part (d).

The attachment is being provided in a separate file.

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Response to Commission Staff's Supplemental Request for Information
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Case No. 2022-00402

Question No. 22

Responding Witness: John Bevington

Q-22. Refer to the Direct Testimony of John Bevington (Bevington Direct Testimony), page 13, lines 15-23.

a. Explain why LG&E/KU have not viewed rooftop solar as a demand-side resource and provide documentation that supports this assertion.

b. Explain why LG&E/KU are not pursuing the rooftop solar incentives as a DSM program.

c. Explain how and why rapid growth is relevant to the issue of whether future incentives from a DSM-based program are necessary and why such incentives could cause customer confusion.

A-22.

a. The Companies have not viewed rooftop solar as a demand-side resource because rooftop solar, or solar mounted in any location, would generate electricity, or provide a supply-side resource. To the best of the Companies' knowledge, the Commission has not approved rooftop solar, or any solar generation, as a demand-side resource in Kentucky.

b. See the response to part (a). As noted on page 14 of Mr. Bevington's testimony, the Companies are willing to explore rooftop solar as a demand-side resource by researching possible programs and regulatory treatment in other jurisdictions.

c. Notwithstanding the response to part (a), or that as a utility supply-side resource rooftop solar is more expensive than other forms of solar generation,[10] customers are already installing rooftop solar on their own

[10] *See, e.g.,* National Renewable Energy Laboratory, "Winter 2023 Solar Industry Update" at 25 (Jan. 26, 2023), available at https://www.nrel.gov/docs/fy23osti/85291.pdf (accessed Apr. 24, 2023); Lawrence Berkeley National Laboratory, "Utility-Scale Solar, 2022 Edition" at 18 (Sept. 2022), available at https://emp.lbl.gov/sites/default/files/utility_scale_solar_2022_edition_slides.pdf (accessed Apr. 24, 2023).

without utility-sponsored incentives.[11] Furthermore, the Inflation Reduction Act (IRA) provides an increase to the investment tax credit to homeowners, which may further accelerate rooftop solar installations. This suggests that any additional utility-sponsored incentives in the form of a DSM program might have a significant free-rider component if the program were not carefully crafted.

In addition, navigating the variety of issues a homeowner might confront concerning a solar installation, including choosing a solar installer, understanding how to apply for various government incentives, applying for net metering, and understanding how those matters fit together, could be daunting and confusing. Again, any DSM solar program, if cost-effective, would also have to be well designed and delivered to ensure it minimizes any additional confusion or burden on the customer.

[11] *See, e.g.,* Exhibit TAJ-1 at 29-32.

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Case No. 2022-00402

Question No. 23

Responding Witness: John Bevington / Stuart A. Wilson

Q-23. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 Demand-Side Management and Energy Efficiency Program Plan, pages 5–6, indicating that the DSM/EE Program Plan is intended to continue to contribute significant energy savings while recognizing that known potential for energy savings is forecasted to decline by approximately 12 percent.

a. Explain why LG&E/KU are proposing an extensive DSM/EE portfolio if known potential is forecasted to decline.

b. Explain whether the forecasted decline in potential is benefiting LG&E/KU from a capacity need and cost savings perspective.

c. Explain how increasing market saturation of efficient technologies, new building codes, and changes in federal equipment standards will impact LG&E/KU's proposed DSM/EE programs' cost-effectiveness and overall potential.

d. Explain how these DSM/EE programs will provide LG&E/KU demand and grid stability in comparison to the proposed building of the NGCC's.

A-23.

a.- c. A decline in forecasted energy efficiency potential means that it is more difficult and expensive for a utility to achieve energy and demand savings through DSM programming because the baseline for customer implementation of energy efficiency has increased. Widespread adoption of efficient technologies, new building codes, and changes in federal equipment standards all generally raise the baseline for energy efficiency. In each case, because customers are already implementing the types of energy efficiency the Companies would incentivize through DSM programming, achieving incremental energy efficiency becomes more costly. For instance, as customers have adopted LED lights, the potential for energy savings through DSM-EE programs involving LED lighting has decreased. This does not mean that the Companies are not benefitting from the widespread adoption of these efficiencies; the Companies' resource plan includes the energy and demand savings from historical LED lighting technology. Even though potential is declining, it is not zero; therefore, there are still opportunities to capture and include cost-effective DSM-EE in the Companies' overall resource plan. The Companies' DSM-EE Program Plan presents a robust, cost-effective portfolio of programs to economically pursue and realize the potential savings that remain.

d. It is unclear what is intended by "how these DSM/EE programs will provide LG&E/KU demand and grid stability in comparison to the proposed building of the NGCCs." The proposed NGCC units will assist the Companies in serving customers and satisfying minimum reserve margin requirements at the lowest reasonable cost. They will also provide around-the-clock, year-round energy to meet customers' energy requirements in all seasons, daylight conditions, and weather conditions. The Companies' proposed dispatchable DSM programs will provide valuable demand-limiting and -reducing capabilities over a limited set of hours each year that will cost-effectively help reduce loss of load expectation after minimum reserve margins have been met.[12] Non-dispatchable DSM-EE programs help reduce energy requirements in various ways and to differing extents year-round, which the Companies addressed in their load forecast.[13]

[12] *See, e.g.,* Exhibit SAW-1 Section 4.6.2.
[13] *See, e.g.,* Exhibit TAJ-1 Section 3.5.

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Question No. 24

Responding Witness: Lana Isaacson

Q-24. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, pages 30-31.

a. State whether there are any differences between LG&E/KU's 2016 appliance recycling program, and the appliance recycling program LG&E/KU are proposing in this application. If there are differences, describe the differences.

b. Provide the total resource cost (TRC) score from the 2016 appliance recycling program before the program was terminated.

A-24.

a. The main differences between the prior program and the new program are the participation volume and corresponding budget. The prior program targeted removing 10,000 appliances per year and the new offering targets removing 8,120 appliances per year by 2028. Thus, the new total budget is also approximately 30% lower (= 1 - $8.9 million proposed / $12.8 million prior).

b. For the period of 2015-2018, the TRC score for the program was 2.26.[14]

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[14] *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*, Case No. 2014-00003, Exhibit MEH-1 at 14 (Ky. PSC filed Jan. 17, 2014).

CONFIDENTIAL INFORMATION REDACTED

KENTUCKY UTILITIES COMPANY
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Question No. 25

Responding Witness: John Bevington

Q-25. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, page 41. Provide the software vendors LG&E/KU have met with to discuss software that can manage enrollment, accurately calculating savings, and issue incentives to customers enrolled in multiple programs.

A-25. The Companies are still in the process of vetting and investigating possible vendors which includes formal processes like Requests for Proposals. To validate the availability of possible solutions and software technology currently available in the market, the Companies have discussed software functionality with the following vendors: [redacted]. Through this process, the Companies have verified that software solutions exist which are capable of handling customers enrolled in multiple programs including the specific aspects of participation mentioned above. The names of the vendors are confidential and provided pursuant to a petition for confidential protection.

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Question No. 26

Responding Witness: Lana Isaacson

Q-26. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, page 42.

a. Provide a further explanation how LG&E/KU are planning to affect the timing and level of charging for electric vehicles and electric vehicle equipment.

b. Explain how the participants in the Optimized Charging subcomponent will be able to set the parameters for LG&E/KU to issue signals or interrupt service.

c. Explain whether the Optimized Charging will be based on a critical peak pricing concept so that LG&E/KU will charge the customers a different rate to charge their EV's during higher peak times.

d. Explain whether Optimized Charging participants can override the signals or interruption based on the parameters that they set. If so, explain whether the participants will be able to qualify for the incentive in that given month.

e. Explain whether there is a rate structure that is connected to the Optimized Charging subcomponent. If so, provide the rate structure or reference to current rates.

A-26.

a. Contingent on the technical capabilities of the optimized charging software vendor, the Companies plan to optimize participant EV charging by shifting load away from peak hours and times of system contingencies, smoothing charging, and staggering charging among EVs connected to the same transformer while adhering to the parameters provided by each participant.

b. During enrollment, optimized charging software vendors typically ask participants when they need their EV to be charged and what range they want it to have at the end of the charging session. Optimized charging software can then alter charging to accomplish the objectives described in part (a) while ensuring a participant's EV has the driving range at the time the participant specified.

c. Optimized Charging will not be based on a critical peak pricing concept in that the electricity a participant uses to charge an EV will be priced according to the rate for the meter that measures the load of the electric vehicle supply equipment. Optimized Charging will allow the Companies to adjust a participant's EV charging to reduce or eliminate its impacts on peaks and each participant will receive a fixed monthly incentive, but there will not be a direct rate impact or price signal to a participating customer of the kind traditionally used in critical peak pricing rates.

d. The Companies do not have a software vendor for the optimized charging subcomponent, so specific guidelines have not been established. The Companies may set a limit for monthly overrides to receive an incentive if supported by the selected software vendor.

e. The Optimized Charging subcomponent will be available only to residential customers who are not on time-of-day rates.

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Question No. 27

Responding Witness: Lana Isaacson

Q-27. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, pages 48–50.

a. Explain how long LG&E/KU anticipate a peak event lasting and when peak events are expected to occur.

b. Explain whether LG&E/KU plan on making the 25 peak time events flexible and allow customers to use peak time events year-round at their convenience or if LG&E/KU anticipate allocating a set number of the events to the summer and a set number of events to the winter.

c. Explain the circumstances in which a customer enrolled in the program would no longer be considered an active participant, including how many times a customer would have to decline to participate to not receive the bonus.

d. Explain whether this program would be more beneficial for customers who have smart thermostats or other enabling technology.

A-27.

a. Peak time events are at least one hour long and can last several hours. The Companies do not currently have a vendor for peak time rebates so specific guidelines, like maximum event duration, have not been established. Peak time events are expected to occur to during system contingencies or high demand, which typically happen when temperatures reach extreme highs or extreme lows.

b. To allow more operational flexibility, the Companies do not intend to allocate a set number of events to summer and a set number of events to winter. It is possible that the Companies may not need a peak time event during a season of a particular year.

c. See the response to part (a). The Companies will work with the vendor, once selected, to establish specific guidelines including the number of times a customer would need to opt out to not receive the annual incentive.

d. Peak Time Rebates programs are beneficial specifically because they do not require smart thermostats or other enabling technologies to participate, which makes them accessible to more customers. This program is unique in that there truly is no barrier to participate that exists in all other Demand Response Programs (a Smart Thermostat for BYOT, a Central AC system for DLC, an EV Charger at home). Smart thermostats and other enabling technology may make Peak Time Rebates more beneficial particularly if they allow participants to control electrical equipment remotely.

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Question No. 28

Responding Witness: John Bevington

Q-28. Refer to Bevington Direct Testimony, Exhibit JB-1, 2024-2030 DSM-EE Program Plan, Appendix D, 2022 Potential Study Projection, page 10. Provide the Technical, Economic, and Achievable Potential for each of the selected programs that are included in the portfolio.

A-28. The Companies did not calculate the program specific potential for the 2024-2030 DSM-EE Program Plan.[15] The potentials correspond to sectors and the various measures available to the sectors and were used to inform the programs presented in the DSM Plan.

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[15] *See* Exhibit JB-1, Appendix D at 2, n.3.

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Question No. 29

Responding Witness: Lana Isaacson / Tim A. Jones

Q-29. Refer to the Isaacson Testimony, Exhibit LI-2 2023 LG&E and KU Demand Response Assessment, Appendix A, page A-3.

a. Explain the basis using a 6.8 percent discount rate and provide any documents that support the use of that rate.

b. Explain why Cadmus is using the California Public Utilities Commission 2016 demand response cost-effectiveness protocols.

c. Explain whether the California Public Utilities Commission has provided updated demand response cost-effectiveness protocols. If so, explain the differences between the 2016 protocols and the most recent updated protocols.

d. Provide a further explanation of how the assumed 20-year product life cycle relates to each of the proposing DSM/EE programs.

e. Provide further explanation of why Cadmus used 5.8 percent and 6.2 percent line loss figures for LG&E/KU. Explain how these different figures were used by Cadmus and whether these figures were used in LG&E/KU's most recent IRP.

f. Explain whether and how LG&E/KU differentiate between service territories when deciding DSM programs. If LG&E/KU do not differentiate between service territories, then explain why LG&E/KU are using separate line loss calculations.

A-29.

a. See attached. As shown on page 6 of the attached document, 6.75% (rounded to 6.8% in Exhibit LI-2) was the correct discount rate for the Companies at the time Cadmus performed the 2023 LG&E and KU Demand Response Assessment dated April 1, 2021, based on the Companies' then-applicable capital structure, requested base-rate return on equity,[16] debt cost, and tax rate.

b. The California cost-effectiveness tests are the most widely accepted methodology for this type of analysis across most jurisdictions in the US. The Commission has required the use of the California cost-effectiveness tests for 25 years,[17] and it has recognized that they are "widely used in the evaluation of DSM programs."[18] The 2016 Demand Response Cost-Effectiveness Protocols use the tests described in the California Standard Practice Manual.

c. No, the most recent version is the 2016 Demand Response Cost-Effectiveness Protocols.[19]

d. The 20-year assumption of a product (measure) life reflects that the individual life of a measure is expected to be in existence and operational for 20 years. For example, for a BYOT program, a measure (in this case a thermostat) that is enrolled in the program is assumed to operate and provide benefits for 20 years.

e. Line loss estimates reflect that any energy saved at the customer's premise is actually saved at the generating source adjusted for line loss. These line loss rates are consistent with those used in load forecasts over the past decade, which would include this CPCN filing as well as the 2021 IRP referenced in the question, as discussed in Exhibit TAJ-2 in Sections 3 and 5.2.1.1. See also Exhibit TAJ-3 at July2022_Forecast\Electric\4_Demand_Forecasts\1_Hourly_Demand\LDC\Data\HourlyDemandForecastInputs_OvernightCharging_2023BP.xlsx.

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[16] *See, e.g., Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, Direct Testimony of Adrien McKenzie at 7 (Nov. 25, 2020); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Meter Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, Direct Testimony of Adrien McKenzie at 7 (Nov. 25, 2020).

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

[18] *See, e.g.*, *Tariff Application of Columbia Gas of Kentucky, Inc. to Continue Its Energy Efficiency Conservation Rider and Energy Efficiency Conservation Program*, Case No. 2016-00107, Order at 3 (Ky. PSC Oct. 11, 2016).

[19] *See* Demand Response Cost-Effectiveness, California Public Utilities Commission, *available at* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness

Specifically, see the tabs named "LossFactorAdjustment" (cells L1:M3) and "LossRateCheck" (column E).

f. The Companies offer one DSM program to all customers. But in cost-effectiveness modeling, the Companies must differentiate between service territories because they have separate rate structures. In order to compute the various cost effectiveness tests that utilize bill impacts, either as a cost (RIM Test) or as a benefit (Participant Test), utility specific information needs to be incorporated into the model.

The attachment is being provided in a separate file.

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Question No. 30

Responding Witness: Lana Isaacson

Q-30. Refer to the Isaacson Testimony, Exhibit LI-2 2023 LG&E and KU Demand Response Assessment, Appendix C, Table C-1, page C-27. Provide the Achievable Potential for each program listed in a similar table.

A-30. The Companies did not calculate program specific Achievable Potentials. See also the response to Question No. 28.

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Question No. 31

Responding Witness: Robert M. Conroy / Stuart A. Wilson

Q-31. Refer to the Direct Testimony of Robert Conroy, page 7, lines 19–21, regarding the return on earnings (ROE) percentage used in the Demand Side Management Cost Recovery Mechanism (DSMRC). Refer also to Isaacson Testimony, Exhibit LI-6 – CONFIDENTIAL LAK_AvoidedCapacityCost, page 6, Table 8, which applied a different ROE percentage to determine avoided capacity costs. Explain why a 9.925 ROE was not used to calculate avoided capacity costs but was used to calculate the DSMRC.

A-31. KRS 278.285(2)(b) specifically authorizes "incentives designed to provide financial rewards to the utility for implementing cost-effective demand-side management programs." That has included an incentive ROE for the capital components of DSM-EE programs (DSM Capital Cost Recovery, "DCCR").[21] It was therefore appropriate to use a base-rate ROE to calculate avoided capacity costs and to use a higher incentive ROE to calculate the DCCR component of the DSMRC.

[21] *See, e.g., 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 21, 28, and 34 (Ky. PSC Oct. 5, 2018) (approving incentive ROE of 10.2%, 50 basis points higher than then-most recently approved base-rate ROE od 9.7%).

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Question No. 32

Responding Witness: Stuart A. Wilson

Q-32. Refer to LG&E/KU's response to Staff's First Request, Item 4, regarding NGCC and SCCT ramp rates. Provide and explain the ramp rate LG&E/KU assumed for new SCCT units at each step of the resource assessment.

A-32. The ramp rates for new NGCC and SCCT units are such that any unit can move from minimum load to maximum load or vice versa within an hour. Because PLEXOS and PROSYM are hourly models, ramp rates for the NGCC and SCCT resource proposals are nonbinding constraints that have no effect on the analysis and are not included in the modeling. Ramp rates are relevant only for sub-hourly dispatch considerations and not in hourly model runs used in the Resource Assessment.

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Question No. 33

Responding Witness: Lonnie E. Bellar

Q-33. Refer to LG&E/KU's response to Staff's First Request, Item 4a. Provide the ability of the proposed NGCC to burn hydrogen on a percent of energy basis rather than a percent of volume basis.

A-33. The 30-50% hydrogen by volume blend equates to 12.5-25% on an energy basis assuming a constant volume of fuel (Natural Gas or Natural Gas and Hydrogen blend) and a 3.0 to 1.0 ratio of natural gas energy content to hydrogen energy content. See the responses to AG 2-7 and KCA 2-51(b), for additional detail.

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Question No. 34

Responding Witness: Lonnie E. Bellar

Q-34. Refer to LG&E/KU's response to Staff's First Request, Item 4c. Provide the ability of current and future SCCTs to accept hydrogen on a percent of energy basis rather than a percent of volume basis.

A-34. The 5% hydrogen by volume originally submitted equates to 1.7% on an energy basis assuming a constant volume of fuel (Natural Gas or Natural Gas and Hydrogen blend) and a 3.0 to 1.0 ratio of natural gas energy content to hydrogen energy content.. See the response to AG 2-7, for additional detail.

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Question No. 35

Responding Witness: Robert M. Conroy

Q-35. Refer to LG&E/KU's response to Staff's First Request, Item 7. Explain the impact to LG&E/KU's financial incentive if the Commission were to deny LG&E/KU's request to use the 50 basis-point ROE adder in the DSMRC.

A-35. The impact to KU would be a $5,461 decrease and the impact to LG&E would be a $5,602 decrease for a total decrease to the Companies of $11,603. In response to PSC 1-7, the Companies described the Commission's historical approval of an ROE adder for DSM-EE programs. This approval is in alignment with KRS 278.285 which twice states the Commission may find reasonable and approve DSM-EE proposals containing incentives to encourage utilities to offer cost-effective DSM programs. The 50-basis point ROE adder proposed in this matter is precisely the type of incentive that has been and will continue to be effective in encouraging the Companies to offer such programs, including the programs offered in this case.

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Question No. 36

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

Q-36. Refer to LG&E/KU's response to Staff's First Request, Item 9. Confirm that the tables depicting forecasted ozone emissions reflect the additions of SCRs on Ghent Unit 2 and Mill Creek Unit 2 in 2026.

A-36. Confirmed.

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Question No. 37

Responding Witness: Philip A. Imber

Q-37. Refer to LG&E/KU's response to Staff's First Request, Item 13. Explain whether the discussion of the CO2 equivalent of greenhouse gasses being less than 25,000 metric tons per year include the two proposed NGCC units at Mill Creek and Brown. Include in the response the annual emission levels for the two NGCC units.

A-37. The discussion of the CO_2 equivalent of greenhouse gasses being less than 25,000 metric tons per year do not include the two proposed NGCC units at Mill Creek and Brown because the IRA methane emissions trigger is specific to applicable facilities pursuant to subpart W of part 98 of title 40, Code of Federal Regulations. Large end-users, like the NGCCs, and their metering and regulating equipment and pipeline which would supply them from the natural gas transmission pipelines are not required to report greenhouse gas emissions under subpart W.

That being said, the potential CO_2 equivalent of greenhouse gasses from the two NGCC units as submitted in their Title V air permit applications are:

Mill Creek NGCC = 2,214,149 tons per year (2,008,233 metric tons)
Brown NGCC = 2,214,260 tons per year (2,008,333 metric tons)

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Question No. 38

Responding Witness: Lana Isaacson

Q-38. Provide a cost-effectiveness analysis for each program identified in LG&E/KU's response to Staff's First Request, Item 21a–g.

A-38. See attached for the cost-effectiveness analyses for the three programs the Companies previously stated they would perform in response to PSC 1-20(e)-(g). For the remaining four programs in PSC 1-20(a)-(d), the Companies have begun developing the program parameters and performing cost-effectiveness analyses. The Companies expect these analyses will be complete no later than May 22nd and will supplement this response with the analyses.

Please note that the cost-benefit analyses for the three programs noted use different avoided capacity costs than the avoided capacity cost reflected in the cost-benefit analyses the Companies filed in the December 2022 Application. The avoided capacity cost used in the cost-benefit analyses filed in December 2022 was the levelized cost of a simple cycle CT installed in 2028, which is an approach consistent with the Companies' past DSM-EE cost-effectiveness analyses. Subsequently, in discovery requests from Commission Staff and interveners, as well as in the informal conference held on April 17, 2023, the Companies received questions about which avoided capacity cost is used in DSM-EE cost-effectiveness calculations. The Companies therefore decided to refine their avoided capacity cost approach to evaluate the programs the Commission Staff has asked the Companies to assess; namely, the attached cost-benefit analysis of the three programs the Companies have been able to analyze to date uses avoided capacity costs for a simple cycle CT for dispatchable DSM, or demand response, programs, and it uses an NGCC unit's costs properly considered over time for energy efficiency programs.

For the sake of consistency, the Companies are also attaching new cost-effectiveness results for their proposed DSM-EE programs using the updated avoided capacity costs. The update does not materially impact the cost-effectiveness of the Companies' proposed programs; the portfolio TRC decreases from 1.54 to 1.50.

The attachments are being provided in separate files.

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Question No. 39

Responding Witness: John Bevington / Stuart A. Wilson

Q-39. Refer to LG&E/KU's response to Staff's First Request, Item 21

a. For each program evaluated in JB-1, provide a breakdown of costs as follows, and explain which components were included in the TRC and PAC tests.

(1) Total incremental measure cost.
(2) Total incentive costs.
(3) Total customer costs

b. Explain which of these cost categories were assumed for selection of DSM resources in the PLEXOS model described in Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, page 23.

A-39

a. The TRC score includes both parts (1) and (3). (2) is not part of the TRC calculation. For the PAC Test, part (2) is included. Parts (1) and (3) are not included in the PAC Test.

b. The Companies evaluated dispatchable DSM programs in PLEXOS based on their fixed costs and variable incentive costs. Fixed costs include administration costs and incentive costs that do not fluctuate based on the number of demand response events called. Variable costs include incentive costs that fluctuate based on the number of demand response events called.

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Question No. 40

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

Q-40. Refer to LG&E/KU's response to Staff's First Request, Item 24c. State whether implementation of the Inflation Reduction Act (IRA) resulted in any changes to LG&E/KU's assumptions that would change LG&E/KU's forecasts and explain any such changes, including whether the changes are likely to affect resource decisions.

A-40. On net, the combined effects of the IRA and the Companies' proposed DSM-EE programs are assumed to reduce the load forecast by almost 200 GWh by the early 2030s. As stated in the response to PSC 1-24(c), "[T]he 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." See also Figure 17 on page 17 of Exhibit TAJ-1 and the Jones Testimony at page 15 beginning on line 13. The proposed changes to the Companies' supply- and demand-side resources account for the impact of the IRA on the load forecast, but it is unknown whether the IRA caused the Companies' resource decisions to be different than they otherwise would have been.

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Question No. 41

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

Q-41. Refer to LG&E/KU's response to Staff's First Request, Item 27e.

a. Explain whether the BrightNight Marion County project will be completed and ready to generate and put energy onto the transmission network when it is transferred to LG&E/KU. If not, explain at what stage in the construction LG&E/KU will take possession and what will need to be completed before energy can be placed on the network

b. Explain the differences in project permitting requirements that reduce the execution risk for a utility as compared to solar merchant generation developers.

A-41.

a. Yes, the Companies will take ownership of the Marion County project when it is capable of generating power, but before it injects energy onto the transmission network. The Companies' ownership of the Marion County project is required prior to injecting energy onto the transmission network.

b. Project permitting requirements are similar between utility and solar merchant generating developers. The main difference is that the Companies are exempt from planning and zoning law pursuant to KRS 100.324 and *Oldham County Planning and Zoning Commission v. Courier Communications Corporation*, 722 S.W.2d 904 (Ky. App. 1987).

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Question No. 42

Responding Witness: Lonnie E. Bellar

Q-42. Refer to LG&E/KU's response to Staff's First Request, Item 28. Refer also to the Wilson Testimony, Exhibit SAW-1, page 39.

a. Provide the status of OVEC's compliance with current, pending, and expected environmental rules

b. If not addressed above, explain the anticipated costs of complying with new or expected environmental regulations

c. If OVEC were to retire in 2028, explain what costs by category would fall to LG&E/KU and LG&E/KU's ratepayers.

A-42.

a. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The information provided summarizes the Companies' most recent understanding of OVEC's compliance with environmental rules. The Companies do not have updates from OVEC regarding very recently published EPA rules.

b. See the response to part (a).

c. The Companies' customers would be responsible for accelerated debt principal or make-whole payments, accelerated demolition and decommissioning costs, postretirement benefit costs, and potential other contractual requirements.

The attachment is being provided in a separate file.

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Question No. 43

Responding Witness: John Bevington

Q-43. Refer to LG&E/KU's response to Staff's First Request, Item 31d.

a. Provide the current state of negotiations with BlueOval SK for 300 MW of renewable energy.

b. If LG&E/KU's application in this proceeding was approved as proposed, explain whether LG&E/KU would issue an RFP for an additional 300 MW of renewables to serve BlueOval SK.

A-43.

a. BlueOval SK signed a special contract for electric service on February 24, 2023 which was filed with the Commission for approval on April 14, 2023 in Case No. 2023-00123. In Section 8.01 of the special contract, KU and BlueOval SK acknowledge that BlueOval SK has a renewable energy objective to obtain from KU up to 300 MW of Solar Generation from a solar generation resource during the term of the special contract. Pursuant to the special contract, the parties have agreed to negotiate in good faith in the future a separate bilateral contract for up to 300 MW of solar generation, subject to the Commission's approval. The parties have also agreed to meet on a semi-annual basis to discuss renewable energy capacity at least until such a contract is in place.

b. See the response to part (a). The solar projects identified in the application are part of the overall generation resource plan to serve the needs of the entire system.

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Question No. 44

Responding Witness: Robert M. Conroy

Q-44. Refer to LG&E/KU's response to Staff's First Request, Item 31 and Item 40. Confirm that a residential customer with a home EV charger can take service under Tariffs RS, RTOD Energy, or RTOD Demand.

A-44. A residential customer with a home EV charger can take service under one of the three residential rate schedules: RS, RTOD-Energy, or RTOD-Demand. In addition, Rates RTOD-Energy or RTOD-Demand are available to a residential customer with a detached garage on Rate GS where the energy usage is no more than 300 kWh per month who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:

a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises;
b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.

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Question No. 45

Responding Witness: Stuart A. Wilson

Q-45. Refer to LG&E/KU's Response to Staff's First Request, Item 33a. Account for the PLEXOS's retirement of the existing DSM programs if the programs were considered cost effective in the DSM analysis.

A-45. In the DSM analysis, dispatchable DSM programs were evaluated with the assumption that 1 MW of dispatchable DSM could avoid 1 MW of SCCT capacity. However, the Companies' Stage One analysis demonstrates that neither dispatchable DSM nor SCCT is a cost-effective means of meeting minimum reserve margin targets and meeting the significant need for energy resulting from coal unit retirements. See Section 4.4 of Exhibit SAW-1 beginning on page 22. In the Stage Three analysis, dispatchable DSM was evaluated as a means of cost-effectively improving the reliability of the portfolio. Despite the fact that limited-duration resources such as dispatchable DSM do not contribute to reliability in the same way that fully dispatchable resources do, the Companies' analysis shows that the proposed dispatchable DSM portfolio is a more cost-effective means of improving reliability than SCCT at the reserve margins evaluated. Adding SCCT had a more favorable impact on LOLE than dispatchable DSM, but at a much higher cost. See Section 4.6.2 in Exhibit SAW-1 beginning on page 36.

KENTUCKY UTILITIES COMPANY
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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 46

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

Q-46. Refer to LG&E/KU's response to the Staff's First Request for Information, Item 35.

a. State whether an analysis been conducted for a KU RTOD-Demand customer to examine the economics of battery storage for demand reduction. If not, explain why.

b. State whether LG&E/KU have considered demand reduction savings residential customers could see from battery storage if, as LG&E/KU have modeled, new loads from adoption of electric vehicles and heat electrification accelerates as predicted.

c. State whether LG&E/KU have considered the economics and adoption of distributed battery storage by commercial and industrial customers, which have higher energy and demand charges and could have lower battery costs through the purchase of more than one battery system as suggested by the Forbes article cited in LG&E/KU's response to the Staff's First Request for Information, Item 35.

A-46.

a. No. KU has only three RTOD-Demand customers, and to the best of the Companies' knowledge and information, neither they nor any of the Companies' other RTOD customers (energy or demand) have distributed battery energy storage. Moreover, the Companies have a total of only eight RTOD-Demand customers. Presumably, if customers could achieve net savings by acquiring distributed energy storage and taking service under RTOD-Demand, there would be more than eight customers taking service under the rate. (Note that the Companies' RTOD-Demand and RTOD-

Energy rates have been available since mid-2015.[21]) The Companies therefore assume that the economics of distributed battery energy storage under RTOD-Demand are not attractive.

b. See the response to (a). There is no reason to expect that adding electric heating or electric vehicle loads would change the number of customers or would affect the economics, and therefore the adoption, of distributed battery energy storage under RTOD-Demand, which is the only residential rate with a demand charge.

First, electric vehicle chargers (or electric vehicles themselves) can be equipped with charging equipment that can charge during designated times, and it would significantly increase energy consumption to charge a distributed battery and then use it to charge an EV battery. Presumably, customers on RTOD-Demand would set their electric vehicle charging to occur off-peak, providing no reason to invest in a separate battery and incur the additional energy cost of using a battery to charge a battery.

Second, with regard to electric heating, KU's customers already have an estimated electric heating penetration above 60%.[22] That there are currently only three KU RTOD-Demand customers strongly suggests that adding electric heating will have little effect on customers' interest in such storage; if having electric heating made adding distributed battery energy storage and moving to rate RTOD-Demand economical, the Companies would expect to have more than three RTOD-Demand customers. That there are not more KU RTOD-Demand customers suggests that the economics of adding distributed battery energy storage and moving to rate RTOD-Demand are not compelling, even with electric heating load.

c. Part of the premise of the question is incorrect as stated, "[C]ommercial and industrial customers … have higher energy and demand charges …." Other than rates GS and GTOD, no commercial or industrial rate has a higher energy charge than any residential rate for either of the Companies. Also, KU's RTOD-Demand on-peak demand rate is higher than all other KU time-differentiated demand rates except GTOD-Demand, and LG&E's RTOD-Demand on-peak rate is close to other LG&E time-differentiated demand rates except GTOD-Demand.

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[21] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2014-00371, Order (Ky. PSC June 30, 2015); Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, Case No. 2014-00372, Order (Ky. PSC June 30, 2015).

[22] *See* Exhibit TAJ-1 Section 3.8.

But the absolute values of the rates are not important for customers' battery economics; rather, it is the *spread* between time-differentiated rates that matters because the value a battery could add is only in moving energy in time (at a cost in energy consumed by the battery). The greatest spread between any of the Companies' on-peak and off-peak demand rates is in KU's Rate GTOD-Demand, which has a spread of $8.69/kW-month between its on-peak demand rate ($14.16/kW-month) and its off-peak demand rate ($5.47/kW-month). Moreover, KU's GTOD-Demand on-peak demand rate is the highest peak demand rate of any of the Companies' time-differentiated demand rates, so if a customer could reduce on-peak demand with a battery and have *no* offsetting increase in demand related to battery charging in non-peak periods, KU GTOD-Demand would be the most compelling rate schedule to pursue such savings. Yet today, KU has over 85,000 Rate GS customers and *zero* Rate GTOD-Demand customers—even though GTOD-Demand has been available to customers for almost two years. That suggests that even the highest demand-rate spread currently in the Companies' rates is not motivating Rate GS customers to acquire distributed battery energy storage and move to Rate GTOD-Demand. And if the largest demand-rate spread is not motivating customers to pursue such storage, it is reasonable to infer that other commercial or industrial customers with smaller spreads would be unlikely to pursue such storage to achieve demand-charge savings.

Finally, it is noteworthy that the Companies are aware of only two commercial or industrial customers with distributed battery energy storage that are on rates with a demand charge.[23] Both of those customers are currently on Rate PS, which does not have time-differentiated demand or energy rates. Thus, of the Companies' 38 other commercial or industrial customers on rates with demand charges whose batteries should be known to the Companies if they existed (because the customers are also net metering customers), *zero* have distributed battery energy storage. To the extent other commercial or industrial customers have batteries about which they have not informed the Companies, whatever effect they have had on load is already reflected implicitly in the Companies' load forecast.

[23] Namely, Rates GTOD-Demand, PS, TODS, TODP, RTS, and FLS.

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Question No. 47

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

Q-47. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, pages 18–20 and 55–59.

a. State whether LG&E/KU reflect differences in the terms of coal and natural gas contracts when determining the gas to coal price ratios. If so, explain how they are reflected. If not, explain why not.

b. Explain whether longer term contracts typically are available for coal purchases as opposed to gas purchases. If so, explain why coal prices used for modeling should not remain constant for a few years before being stepped up or down based on the relevant coal to gas ratio to reflect the longer term fixed prices. If not, explain the why they are not.

A-47.

a. The fuel price scenarios used in this analysis are based on three possible natural gas price paths that depend on the fundamentals of supply and demand. These fundamental price scenarios are not impacted by the contracting activities of the thousands of market participants, including the Companies. As discussed in Exhibit SAW-1, Section 2.1.3, the U.S. Energy Information Administration developed low, mid, and high natural gas price scenarios using alternative views on the market fundamentals that could impact both the supply of and demand for natural gas. Because coal prices have historically demonstrated a relationship to natural gas prices, the Companies used the range of historical relationships of natural gas and coal prices to derive a range of possible coal price scenarios, with a particular emphasis on the central tendency of that historical range (i.e., Mid CTG Ratio) across the three natural gas price scenarios.

From a finance theory perspective, prices will tend to follow a random walk around the underlying fundamentals that reflect various short-term events. But attempting to incorporate and project a particular procurement strategy that would assume outperforming the market consistently over 30 years to take advantage of these random price fluctuations would contradict decades of historical experience that traders cannot consistently outperform the index.

Therefore, for purposes of long-term investment decisions like those at issue in this proceeding, evaluating the various assets against a range of possible long-term fuel price scenarios is both necessary and prudent, whereas attempting to forecast underlying procurement or trading strategies of market participants in the coal and natural gas markets will have no impact on the range of possible future fuel prices and, hence, the analysis in this proceeding.

b. As discussed in response to (a), the procurement strategies and activities of thousands of market participants will not impact the fundamental supply and demand scenarios utilized in this analysis. Also, these same strategies and activities would presumably operate in all price scenarios and, therefore, would have no impact on the coal-to-gas spreads.

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Question No. 48

Responding Witness: Stuart A. Wilson

Q-48. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update. Confirm that all updates to this document are highlighted or outlined in orange, and if this cannot be confirmed, identify all updates in this document.

A-48. Confirmed.

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Question No. 49

Responding Witness: Stuart A. Wilson

Q-49. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 23. Confirm that PLEXOS had the ability to pair a battery with a solar facility independently of what may have been included as an RFP response. If not, explain why not.

A-49. The only constraints placed on solar and battery facilities available for selection in PLEXOS were those specified by bidders in the Companies' 2022 RFP. Outside of restrictions from bidders, PLEXOS was free to select any combination of battery or solar facilities. See the response to Question No. 10(e) for further details.

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Question No. 50

Responding Witness: Stuart A. Wilson

Q-50. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 37, Table 20.

a. Assuming that none of the resources listed in the first column of Table 20 are constructed but otherwise using all of the same assumptions used to calculate the loss of load exceptions (LOLE), calculate the summer, winter, and total LOLE for the following portfolios:

(1) Continuing to operate Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls but without constructing new SCRs on Mill Creek Unit 2 and Ghent Unit 2.

(2) Continuing to operate Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls and with new SCRs on Mill Creek Unit 2 and Ghent Unit 2.

(3) Continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls but without constructing new SCRs.

(4) Continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls and with new SCRs as necessary to operate during ozone season.

(5) Continuing to operate Haefling Unit 1 and Unit 2 and Paddy's Run Unit 12, and continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with necessary maintenance and overhauls but without new SCRs.

(6) Continuing to operate Haefling Unit 1 and Unit 2 and Paddy's Run Unit 12, and continuing to operate Mill Creek Unit 1, Mill Creek Unit 2, Ghent

Unit 2, and Brown Unit 3 with necessary maintenance and overhauls and with new SCRs as necessary to operate during ozone season.

b. Identify the unforced capacity value used for each unit listed above to calculate the LOLE in each instance and explain each basis for the unforced capacity value used for each unit.

A-50.

a. The results are summarized in the table below with the following notes:
   - For subparts (3) through (6), "necessary maintenance and overhauls" for Mill Creek 1 are assumed to include the cost of a new cooling tower and the cost of additional water processing capacity for compliance with existing Effluent Limit Guidelines.
   - Minor differences in winter LOLE between subparts (1) and (2), subparts (3) and (4), and subparts (5) and (6) are due to random drawing of unit availability scenarios and can be ignored. The same is true for the difference in summer LOLE between subparts (1) and (3).

Question Subpart	2028 LOLE		
	Summer (Jun-Aug)	Winter (Jan-Feb, Dec)	Total (12 Months)
(1)	32.46	0.79	37.51
(2)	1.85	0.83	2.86
(3)	32.74	0.31	37.37
(4)	0.48	0.30	0.82
(5)	30.88	0.25	35.15
(6)	0.45	0.24	0.74

b. SERVM does not use unforced capacity values to calculate LOLE. Instead, it uses net capacity (ICAP) and forced outage rates to calculate LOLE. For unforced capacity value, see the response to PSC 1-89(c).

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Question No. 51

Responding Witness: Stuart A. Wilson

Q-51. Refer to LG&E/KU's response to Staff's First Request, Item 42 and Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 51.

a. Explain whether the future retirements of LG&E/KU coal units other than Mill Creek units 1 and 2, Ghent Unit 2 and Brown Unit 3 were factored into the PLEXOS and PROSYM modeling. If not, confirm that the useful life of the remaining coal units extends beyond the study period.

b. Provide an update to Table 30 for LG&E/KU's remaining coal units. Include in the explanation how these values compare to the useful lives of the units.

c. Explain what remaining life/useful life was used as an input in the PLEXOS and PROSYM models.

d. Explain the characteristics of Brown Unit 3 that are primarily driving PLEXOS's retirement of Brown Unit 3 in Stage One, regardless of fuel prices.

A-51.

a. The Companies did not consider future retirements of coal units other than Mill Creek 1 and 2, Ghent 2, and Brown 3 in this proceeding. Therefore, the Companies confirm that the useful life of the remaining coal units extends beyond the study period for the purposes of this analysis (with the exceptions stated below). As stated in Section 3.3 of the 2022 Resource Assessment, to focus this analysis on the decision immediately at hand – Good Neighbor Plan compliance implications for Mill Creek 2 and Ghent 2 and major maintenance requirement for Brown 3 – the Companies have assumed that all of their existing resources will continue to operate throughout the analysis period with these exceptions: Mill Creek Unit 1 will retire as planned in 2024, Paddy's Run Unit 12 and Haefling Units 1-2 will retire in 2025, and OVEC will retire as planned in 2040.

In reality, the useful life of the remaining units will depend on future environmental regulations and the cost of continuing to operate aging units relative to alternative technologies for reliably and cost-effectively meeting customers' energy needs.

b. See the table below. The book depreciation life is based on the most recent depreciation study and reflects the remaining expected useful life of the units under current environmental regulations.

Unit	Age as of 1/1/2022	Age as of 1/1/2035	Age as of 1/1/2050	End of Book Depreciation Life
Ghent 1	47	60	75	2034
Mill Creek 3	43	56	71	2039
Ghent 3	40	53	68	2037
Mill Creek 4	39	52	67	2039
Ghent 4	37	50	65	2037
Trimble County 1	31	44	59	2045
Trimble County 2	10	23	38	2066

c. PLEXOS and PROSYM both assumed all remaining units would operate beyond 2050 for purposes of this analysis (with the exceptions stated in part (a)).

d. Brown 3's retirement regardless of fuel prices has three key drivers. First, it is not accessible by barge, and coal delivered exclusively via rail increases the station's delivered coal costs. Second, it has a high heat rate relative to the Companies' other coal units, which further increases its energy cost. Finally, its stay-open costs are higher than other coal units on a $/MW-year basis due to fewer economies of scale compared to other stations with multiple coal-fired units.

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Question No. 52

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

Q-52. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 5/2, Table 31.

a. State whether the stay open costs listed in Table 31 are the stay open costs that were used for Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 in PLEXOS in Stage One, Step One of LG&E/KU's resource assessment, and if not, identify and describe the differences in stay open costs that were used in that step of the model.

b. Identify the files reflecting the stay open costs for Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 used by PLEXOS in Stage One, Step One of the LG&E/KU's resource assessment.

c. Provide an itemized breakdown of the Ongoing Costs, Overhaul Costs (Standard), Overhaul Costs (Life Extension), and the Environmental Compliance Costs (SCR) in each year for each of the units with as much detail as much detail as possible.

d. For each cost identified in response to subpart c. of this request or included in any way in Table 31 if not separately broken out, explain LG&E/KU's methodology for projecting the cost and each basis for LG&E/KU's estimate of the cost.

e. Provide an itemized breakdown of the total expected capital costs for an SCR on Mill Creek Unit 2 and Ghent Unit 2.

f. Explain the difference between the "Standard" and the "Life Extension" Overhaul Costs and explain specifically how those costs were treated during each of the steps of the resource assessment.

A-52.

a. Yes, the stay open costs listed in Table 31 are the stay open costs that the Companies used for Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 in PLEXOS in Stage One, Step One of the resource assessment.

b. Stay-open costs for these units used in PLEXOS are reflected in "\02_PLEXOS\AnnualCosts.csv" and are also reflected in "\04_FinancialModel\Support\StayOpenCosts\20221207_StayOpenSummary_0308.xlsx" in Exhibit SAW-2.

c. Stay-open costs for Mill Creek 2, Ghent 2, and Brown 3 are summarized in "\04_FinancialModel\Support\StayOpenCosts\20221207_StayOpenSummary_0308.xlsx" in Exhibit SAW-2.

   Details for Ongoing Costs and Overhaul Costs (Standard) are available in "\04_FinancialModel\Support\StayOpenCosts\20221021_StayOpenDetail_MC_0308.xlsx", "\04_FinancialModel\Support\StayOpenCosts\20221021_StayOpenDetail_GH_0308.xlsx", and "\04_FinancialModel\Support\StayOpenCosts\20221021_StayOpenDetail_BR_0308.xlsx" in Exhibit SAW-2.

   Details for Overhaul Costs (Life Extension) are available in "\04_FinancialModel\Support\StayOpenCosts\20220915_Life Extension Capital Costs Final_0308.xlsx" in Exhibit SAW-2.

   Capital associated with SCR construction is attached to part e. Ongoing capital and O&M associated with SCRs are summarized in "\04_FinancialModel\Support\StayOpenCosts\20221206_SCR_CapitalandOM_0308.xlsx" in Exhibit SAW-2.

d. See attached.

e. See the attachments being provided in Excel format. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

f. "Standard" overhaul costs reflect routine major maintenance typically performed on an eight-year overhaul cycle. "Life extension" costs reflect incremental projects that would be needed to extend the life of a unit beyond its current usable life. While the nature of these costs differs, both costs were treated in the same manner in all steps of the Resource Assessment, where the Companies assume that costs for routine maintenance and major overhauls will be reduced in the years leading up to a unit's retirement and that all costs would be avoided after a unit's retirement.

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. 53

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

Q-53. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 55, Table 35.

a. Provide an itemized break down of the Transmission System Upgrade Costs of reflected in Table 35 with specific details, provide a description of each of the transmission systems upgrades reflected in those costs, and explain how those costs were estimated.

b. Explain, with specificity and detail, how the Transmission System Upgrade Costs of reflected in Table 35 were treated during each of the steps of the resource assessment.

c. Provide the Transmission System Upgrade Costs projected in the same manner as in Table 35 and itemized as requested in subpart a. of this Request above if Mill Creek Units 1 and 2, and Brown Unit 3 are retired, and a NGCC is added at Brown.

d. Given that transmission facilities are already present at Mill Creek, and Brown, explain why the existing facilities are inadequate and why the modeled transmission upgrades have such wide cost differentials.

e. Explain whether any of the coal unit retirements require complete removal of the units in order to make room for transmission upgrades or new generation facilities.

f. Identify and describe the ownership share of the transmission upgrades for which costs are reflected in Table 35 and in subpart c of this Request above, and explain how the associated costs will be apportioned between LG&E's and KU's customers.

A-53.

a. See "\04_FinancialModel\Support\TransmissionCapital\CONFIDENTIAL_Generation Replacement Scenarios - Impacts on the Transmission System_2022.docx" in Exhibit SAW-2. Scenario 3 on page 7 lists the projects needed if Mill Creek 1-2 and Brown 3 are retired and SCCTs are added at Mill Creek, Scenario 4 on page 8 lists the projects needed if Mill Creek 1-2 and Brown 3 are retired and an NGCC is added at Mill Creek, and Scenario 11 on page 11 lists the projects needed if Mill Creek 1-2 and Brown 3 are retired and NGCCs or SCCTs are added at Mill Creek and Brown. This document also provides details regarding the methodology of how these costs were estimated.

b. See "\04_FinancialModel\Support\20221206_TransmissionCapital_0308.xlsx" in Exhibit SAW-2. In this file, capital costs for projects identified in the document responding to part (a) were escalated to 2028 dollars. Retiring Mill Creek 1-2 and Brown 3 while only building replacement NGCC or SCCT generation at Mill Creek creates the need for transmission system upgrades with a capital cost ranging from $39 million to $52 million (2028 dollars). However, the total capital cost of transmission system upgrades associated with retiring these units and building replacement NGCC or SCCT generation at both stations is only $4 million (2028 dollars).

   The capital costs related to Scenario 4 and Scenario 3 were added to the capital costs associated with the respective NGCC and SCCT options at Mill Creek. To properly account for the reduced capital spending associated with building generation at both stations, the Companies applied the delta of Scenario 11 less Scenario 4 as a capital reduction associated with the Brown NGCC resource option, and similarly applied the delta of Scenario 11 less Scenario 3 as a capital reduction associated with the Brown SCCT resource option. In total, this method allows the models to accurately reflect the transmission capital regardless of whether a scenario includes generation at Mill Creek and Brown or only at Mill Creek.

   Within PLEXOS, these values were applied to the RFP responses and are reflected in "\02_PLEXOS\BuildCost_GasTransmission.csv" file. These costs were not modeled in PROSYM, which is used solely for modeling production costs, but are reflected in the XM System Upgrades section (columns AC through AF) of the Resources tab of the Financial Model files. The Companies note that in the Financial Model files, costs associated with Mill Creek were de-escalated from 2028 dollars to 2027 dollars.

c. The total transmission capital costs associated with such a scenario would be $988,700 in 2022 dollars. Scenario 2 on page 7 of the document referenced in part (a) lists the project needed. The Companies did not consider this scenario because Brown 3 is needed to support reliability until all resources needed for Good Neighbor Plan compliance are in place, and Brown 3 and a new NGCC at Brown (Brown 12) cannot operate simultaneously due to existing transmission system limitations. Therefore, if the Companies received approval for only one NGCC, it would need to be constructed at Mill Creek. See the response to Question No. 15(c).

d. There are two small upgrades to the existing transmission facilities at Brown ($220,000 total), because the proposed NGCC has a larger capacity than Brown 3. There is a wide cost differential only when a NGCC is not added at the Brown location. Generation at Brown provides significant support to the KU territory, so if that generation is retired and not replaced nearby then transmission system upgrades are needed, which increase costs in that scenario.

e. Complete removal of the retired coal units is not required to make room for transmission upgrades or new generation facilities. However, the Companies will demolish the retired Brown 1 & 2 units prior to construction of the Brown NGGC due to their close proximity to each other.

f. The cost allocation used in the CPCN analysis attributes transmission capital as part of the capital for the NGCCs, resulting in the same split of 69% for KU and 31% for LG&E as the NGCCs.

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Question No. 54

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

Q-54. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 55, Table 35.

a. Explain whether LG&E/KU undertook a transmission analysis regarding any of the proposed solar PPAs, including the four that were selected in the optimal portfolio or the Mercer and Marion solar projects.

b. With respect to the PPAs, including the Marion County project, because solar merchant generators are responsible for transmission system upgrades and interconnection costs, explain what transmission costs would be incurred by LG&E/KU and why these costs are uncertain.

c. Explain whether the transmission costs related to the solar PPAs, and the Mercer and Marion solar projects are included in the PLEXOS and PROSYM modelling runs. If so, explain which transmission costs are included and in which model. If not, explain whether the models may have selected amounts of solar uneconomically at the expense of other generation resources.

A-54.

a. Yes, the proposed solar PPAs and the Marion solar project were evaluated in Appendix A of "\04_FinancialModel\Support\TransmissionCapital\CONFIDENTIAL_Generation Replacement Scenarios - Impacts on the Transmission System_2022.docx" in Exhibit SAW-2. No transmission system upgrades were identified for the Mercer project.

b. The Companies disagree with the assertion in the data request that merchant generators are responsible for transmission system upgrades. See the responses to PSC 1-27 and 1-55.

c. Transmission costs related to the solar PPAs and the Mercer and Marion solar projects were not included in the PLEXOS or PROSYM modeling runs due to the uncertainty associated with these costs and because transmission system upgrade costs for a solar project typically are not a significant portion of the total project cost. See the response to PSC 1-55.

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Question No. 55

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

Q-55. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), 2022 Resource Assessment, Generation Planning & Analysis, March 2023 Update, page 25, Tables 7 and 8. Refer also to Case No. 2022-00098 in which East Kentucky Power Companies (EKPC) indicated that the simultaneous outage of the LG&E/KU's Brown Unit 3 and EKPC's Cooper Station Units 1 and 2 could cause issues in serving load in the southern Kentucky area.[24]

a. Explain whether there would be adequate voltage support for the southern part of the KU system with the retirement of the Brown Unit 3 in a scenario in which the proposed Brown NGCC unit is not added. Include in the response a scenario with EKPC's Cooper Station online and not online.

b. Explain whether a portfolio that retires Brown Unit 3 but does not add the Brown NGCC unit is a viable alternative.

A-55.

a. See the response to part (b). Retiring Brown 3 and not constructing the Brown 12 NGCC is not a viable or prudent alterative assuming no other changes are made to the Companies' recommended portfolio.

Within Exhibit SAW-2 "\04_FinancialModel\Support\TransmissionCapital\CONFIDENTIAL_Generation Replacement Scenarios - Impacts on the Transmission System_2022.docx"; Scenarios 3, 4, 7, and 8 describe the transmission network upgrades that would be required for various scenarios where Brown Unit 3 is retired and the proposed Brown NGCC is not added. The projects listed in this report are what is expected to be needed to ensure there are no thermal overloads or voltage support issues. This analysis assumed that both Cooper Unit 1 and Cooper Unit 2 were on-line but did

[24] Case No. 2022-00098, Electronic 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. (Ky. PSC Mar. 9, 2023), Order, Commission Staff's Report on the 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. at 37.

study the loss of Cooper Unit 1 and Cooper Unit 2 individually as contingency scenarios.

In a real-time scenario where Brown Unit 3 is retired, the proposed Brown NGCC unit is not added, and neither Cooper Unit 1 nor Cooper Unit 2 is available (perhaps due to retirements or other issues), voltage support would at times be an issue on the KU system and the surrounding area. In those scenarios, the Companies would be required to redispatch their existing Brown CT generators (Units 5 – 11) out of economic merit order to provide voltage support in the area. Depending on how severe the voltage support issues are in these scenarios, increasing Brown CT generation may alleviate all the voltage support issues. If not, then additional action would need to be taken to alleviate the remaining voltage support issues, including shedding load.

To lower the risk of real-time voltage support issues, the LG&E/KU annual Transmission Expansion Planning process would identify potential thermal overload or voltage support issues and the necessary transmission upgrade projects to alleviate those issues. For voltage support, these projects could include installing capacitors or building a new source (i.e., transmission line) into the area.

b. Retiring Brown 3 and not constructing the Brown 12 NGCC is not a viable or prudent alterative assuming no other changes are made to the Companies' recommended portfolio. Without Brown 12, the Companies' winter reserve margin would be 21.7%, which is below the minimum target of 24%.

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Question No. 56

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

Q-56. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, March 2023 Update, page 34. Explain why the Mercer County self-build Project and the Marion County asset purchase Project were not included as a resource option to the PLEXOS model in Stage One of the analysis.

A-56. See Mr. Sinclair's Direct Testimony, Sections 4 and 5. The mechanics of the PLEXOS model are such that it assumes that any resource that it is allowed to choose from can and will be available and will perform as assumed for the entirety of the project or contract life. It cannot evaluate uncertainty associated with project development. It also is not well suited to address uncertainty associated with contract performance and post-contract termination replacement risk or uncertainty.

As explained in Mr. Sinclair's testimony, PPA's are a type of "put" option for the developer, whereas owned solar projects will have a greater degree of certainty in terms of both construction and operation. This means that, essentially, PPA solar and Companies-owned solar should be different asset classes from a PLEXOS perspective despite the identical underlying technology, but it was unclear how to represent these relevant differences in PLEXOS. Therefore, the Companies elected to defer the evaluation of Companies-owned solar until after PLEXOS had optimized PPA solar to better evaluate and understand the economic implications of the owned solar projects.

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Question No. 57

Responding Witness: Lonnie E. Bellar / Charles R. Schram

Q-57. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), 2022 Resource Assessment, Generation Planning & Analysis, March 2023 Update, page 34. For the Marion Project:

a. Describe the status of the Marion Project siting and development.

g. Explain whether this project is subject to the Siting Board jurisdiction and, if an application has been filed with the Siting Board, provide the case number.

c. Provide a copy of the asset purchase contract between LG&E/KU and the Marion Project developer or owner.

d. Explain whether a transmission line and substation will have to be constructed to connect the project to LG&E/KU's transmission system and, if so, provide a description of the facilities.

e. Explain whether the developer is responsible for ensuring all the transmission studies are completed.

f. Explain whether there are any transmission network upgrades connected to this project and, if so, explain whether LG&E/KU are paying those costs or reimbursing the developer as part of the contract price.

A-57.

a. The Marion Project developer continues to advance the development of the project and anticipates that all land required for construction will be optioned by the end of Q2 2023.

b. Yes, the Marion Project is subject to Siting Board approval. To the Companies' knowledge, an application has not been submitted to the Siting Board.

c. An asset purchase contract has not been executed between the Marion Project developer and the Companies.

d. The construction of any lead line to the Companies' transmission system will be the responsibility of the developer. The Marion Project is proposed to connect to the existing Lebanon 138kV substation; therefore, a new substation will not be constructed. Instead, the existing Lebanon 138kV substation will be modified by adding a breaker (and other associated equipment) to the existing straight bus configuration.

e. The generator interconnection developer is responsible for ensuring all generator interconnection studies are completed. The Companies are responsible for ensuring all transmission service studies are completed.

f. There were no transmission network upgrades identified to mitigate issues on the transmission system in the generator interconnection studies for this project.

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Question No. 58

Responding Witness: Lonnie E. Bellar

Q-58. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, Generation Planning & Analysis, March 2023 Update, pages 13 and 34. For the Mercer Project:

a. Explain the meaning of the statement, "LG&E/KU's Project Engineering group therefore revised their self-build proposal to suit the proposal at the Mercer County site, resulting in a 120 MW self-build solar proposal in Mercer County . . . . ." Include in the response whether LG&E/KU acquired the proposed project from the developer and the Project Engineering group will develop the project from that stage.

b. Describe the current development stage of the project and whether any land has been acquired or leased.

c. Explain whether a transmission line and substation transmission system upgrades will have to be construction as a part of this project and, if so, whether these costs were included in the modeling.

A-58.

a. The Companies are negotiating with Savion to acquire the assets of their Mercer Solar II project. The acquired assets will be used by the Companies to develop the Mercer Solar project.

b. The current development stage of the Mercer Solar project is approximately 30% (conceptual design). Closure of the property purchase occurred on April 27, 2023.

c. A new substation, connecting to an existing 138kV transmission line, is required for the proposed Mercer Solar project. The direct interconnection costs associated with the proposed Mercer Solar project are included in the modeling. No transmission system upgrades were identified for this project.

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Question No. 59

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

Q-59. Refer to LG&E/KU's response to Staff's First Request, Item 47(a), Attachment 1, 2022 Resource Assessment, Appendix D, 2022 RFP Minimum Reserve Margin Analysis, page D-14.

a. Identify the number of times curtailable service rider (CSR) customers have been interrupted in each of the last five years.

b. Explain whether all customers on the CSR Tariff were interrupted during winter storm Elliott. If not, explain why not.

c. Explain whether the load forecast included all the non-dispatchable DSM program savings that have been proposed by LG&E/KU. If not, explain why not.

d. Explain whether the reserve margin analysis incorporated all the proposed DSM program dispatchable interruption savings. If not, explain why not.

A-59.

a. All CSR customers were physically interrupted three times in the last five years: July 15, 2021, December 23, 2022, and December 24, 2022.

b. Yes. See the response to part (a).

c. Yes. The load forecast includes all the non-dispatchable DSM-EE program savings the Companies have proposed.

d. No new supply-side or dispatchable DSM resources were considered in the analysis to determine minimum reserve margin targets. This analysis considered only existing resources. Then, the minimum reserve margin targets from this analysis were used as an input to the 2022 Resource Assessment where new supply-side and dispatchable DSM resources were evaluated.

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Question No. 60

Responding Witness: David S. Sinclair

Q-60. Refer to LG&E/KU's response to Staff's First Request, Item 48. Explain whether the solar PPAs and the Mercer and the Marion solar facilities, once completed, will be always be dispatched first.

A-60. The Companies will not have the right to dispatch the solar PPA facilities. Unless energy from the PPA facilities is being curtailed by the Interconnection Provider, the Reliability Coordinator, or the Balancing Authority for system reliability purposes, the Companies must take all energy being produced from the solar PPA facilities. The energy from the Companies-owned facilities in Mercer and Marion counties will be dispatchable within the output range allowed by solar irradiance. However, given that the marginal energy cost from the owned solar facilities is $0/MWh, the Companies would not anticipate curtailing their output under normal operating conditions.

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Question No. 61

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

Q-61. Refer to LG&E/KU's response to Staff's First Request, Item 28 and Item 48.

a. Identify and describe the cost of the OVEC energy that LG&E/KU are obligated to take and, explain where in the dispatch stack OVEC be dispatched but for the contractual obligation.

b. If LG&E/KU owned the OVEC units outright, explain whether this would be one of the units being retired as opposed to the units being retired in the preferred portfolio.

c. Confirm that the energy received from OVEC is dispatched first due to the contractual obligation to take the energy regardless of price.

A-61.

a. OVEC energy costs vary with coal costs and are currently in the high $20s/MWh. Its place in the dispatch stack varies based on its costs relative to the energy costs of the Companies' coal units and Cane Run 7 NGCC. Historically, on most days, the Companies dispatch OVEC energy above the minimum take obligation for at least one hour. It should be noted that the Companies' minimum take obligation fluctuates based on the availability and on-line status of the 11 OVEC units. Therefore, the 50 MW minimum take obligation stated in response to PSC 1-48(a) applies only when all 11 units are on-line and the Companies would be able to take up to its full OVEC share of 174 MW. This would typically be the case during summer and winter months when load is higher and not during fall and spring months when some units are down for maintenance and load is lower. The OVEC minimum take obligation is comparable to the minimum output levels associated with any steam generation unit that cannot cycle daily.

b. Because the Companies do not own the OVEC units outright, the Companies have not performed the analysis on the hypothetical suggested by the request.

Regarding the Companies' actual resource portfolio, the Mill Creek 2 and Ghent 2 retirements in this case are being driven by the cost of compliance with the Good Neighbor Plan ("GNP"). Whether or not OVEC continued to operate in the future would have no bearing on the GNP compliance cost for Mill Creek 2 and Ghent 2. The retirement of Brown 3 is being driven by avoiding the cost of major maintenance and stay open costs. These costs would be unaffected by the retirement or operation of the OVEC units. As stated on page 39 in Section 4.6.3 of Exhibit SAW-1, "…the optimal resource portfolio would provide excellent reliability even if OVEC retired early. Therefore, there was no reason to adjust the optimal portfolio solely to address the possibility of early OVEC unit retirements."

c. Not confirmed. Other than the minimum hourly take obligation, the Companies are free to dispatch energy from OVEC based on its energy cost along with the rest of the Companies' generation fleet. See the response to part (a).

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Question No. 62

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

Q-62. Refer to LG&E/KU's response to Staff's First Request, Item 50 and Item 53e.

a. Provide and explain the Present Value Revenue Requirement (PVRR) for the Final Portfolio and the Economically Optimal Portfolio supporting each of the PVRR entries in the table.

b. Provide an update to the Table using the format in part a above by including the value of Renewable Energy Credits (RECs).

c. Explain which party to the four solar PPAs retains the associated renewable energy credit.

d. Explain, if known, whether the developers/owners of the four solar PPAs have figured in the incentives in the Inflation Reduction Act (IRA).

A-62.

a. See the table below. The PVRR entries in the referenced table are based on the PVRR delta of the third and fourth columns and the PVRR delta of the fourth and fifth columns.

PVRR by Fuel Price Scenario, No CO2 Price, $0/MWh RECs ($M, 2022 Dollars)

	Fuel Price Scenario (Gas, CTG Price Ratio)	PVRR of Economically Optimal Portfolio	PVRR of Economically Optimal Portfolio plus Solar Assets	PVRR of Economically Optimal Portfolio plus Solar Assets and Brown BESS (Final Portfolio)
Expected CTG	Low Gas, Mid CTG	34,071	34,324	34,455
	Mid Gas, Mid CTG	38,282	38,478	38,605
	High Gas, Mid CTG	47,217	47,252	47,347
Atypical CTG	Low Gas, High CTG	34,359	34,604	34,734
	High Gas, Low CTG	46,146	46,184	46,262
	High Gas, Curr CTG	53,375	53,326	53,404

b. See the tables below.

PVRR by Fuel Price Scenario, No CO2 Price, $5/MWh RECs ($M, 2022 Dollars)

	Fuel Price Scenario (Gas, CTG Price Ratio)	PVRR of Economically Optimal Portfolio	PVRR of Economically Optimal Portfolio plus Solar Assets	PVRR of Economically Optimal Portfolio plus Solar Assets and Brown BESS (Final Portfolio)
Expected CTG	Low Gas, Mid CTG	33,936	34,153	34,283
	Mid Gas, Mid CTG	38,147	38,307	38,434
	High Gas, Mid CTG	47,081	47,081	47,176
Atypical CTG	Low Gas, High CTG	34,224	34,432	34,563
	High Gas, Low CTG	46,010	46,013	46,090
	High Gas, Curr CTG	53,240	53,155	53,233

PVRR by Fuel Price Scenario, No CO2 Price, $10/MWh RECs ($M, 2022 Dollars)

	Fuel Price Scenario (Gas, CTG Price Ratio)	PVRR of Economically Optimal Portfolio	PVRR of Economically Optimal Portfolio plus Solar Assets	PVRR of Economically Optimal Portfolio plus Solar Assets and Brown BESS (Final Portfolio)
Expected CTG	Low Gas, Mid CTG	33,801	33,982	34,112
	Mid Gas, Mid CTG	38,012	38,136	38,263
	High Gas, Mid CTG	46,946	46,910	47,005
Atypical CTG	Low Gas, High CTG	34,089	34,261	34,392
	High Gas, Low CTG	45,875	45,841	45,919
	High Gas, Curr CTG	53,105	52,983	53,062

c. The Companies receive the RECs along with the four PPAs' solar energy.

d. The Companies provided all RFP respondents an opportunity to revise their responses to consider IRA incentives. See Schram testimony at page 5 and the responses to PSC 1-69 and PSC 1-94. Regardless of how the developers arrived at their pricing, theirs were the most competitive offers the Companies received.

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Question No. 63

Responding Witness: Stuart A. Wilson

Q-63. Refer to LG&E/KU's response to Staff's First Request, Item 52b.

a. Provide a detailed description of the resources that were excluded due to "Pipeline diversity/multiple NGCC per site."

b. Provide a detailed explanation of LG&E/KU's rationale for excluding these resources, including any concerns it has over pipeline diversity and risk factors associated with having multiple NGCCs at a single site.

A-63.

a. The three proposals that were excluded for this reason are each for constructing two 621 MW net summer NGCC units at the Mill Creek (one proposal) or E.W. Brown (two proposals) stations. The NGCC units are exactly the same as the ones the Companies are proposing in their application, but for two units to be collocated at one station.

b. Geographic diversity adds to reliability for any resource by reducing the risk of any station-level or system-level disruptions, including electrical transmission system risk and natural gas delivery risk, if applicable. Because the Companies currently have the option to site the proposed NGCC resources at different locations, the Companies chose this option to allow them to be served from multiple gas transport pipelines. This reduces the concentration of the small but non-zero gas delivery risks. However, future resource siting decisions will be based on site availability at the time.

   Also, placing one NGCC at each site allowed the Companies to fully take advantage of existing electricity transmission infrastructure resulting from the retirement of coal units as opposed to having to construct significant transmission at one site while leaving the transmission at the other site unutilized.

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Question No. 64

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

Q-64. Refer to LG&E/KU's response to Staff's First Request, Item 53f.

a. Because battery storage shifts energy in time and does not produce energy, explain why battery storage should be counted in the reserve margin and why this does not represent double counting of another generation resource's capacity.

b. Explain whether LG&E/KU's solar facilities produce any energy during winter peak hours.

c. Provide a chart showing the solar facilities' expected energy output and LG&E/KU's demand that demonstrates and justifies giving zero capacity credit to solar facilities in the winter heating season.

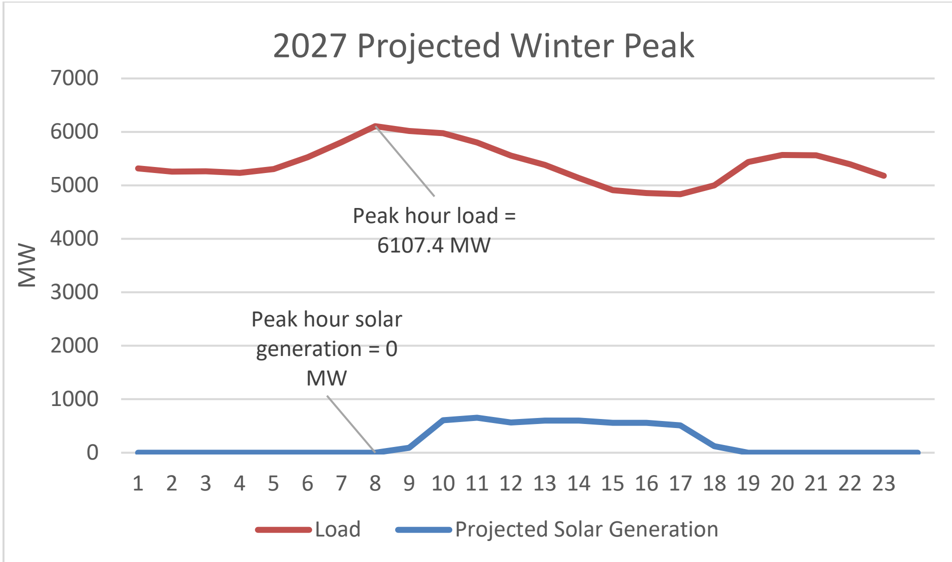
A-64.

a. The Companies assume the battery storage resource would be fully charged at the time of peak, meaning 125 MW from the battery and the capacity from the resource(s) used to charge the battery would be available at the time of peak. Given the capacity of the battery storage resource (125 MW and 500 MWh) relative to the capacity of the Companies' dispatchable resources available to charge the battery (over 7,000 MW) and the ability to charge the battery off-peak, this assumption is reasonable.

b. The Companies have owned and operated solar generation facilities since the June 2016 commissioning of the 10 MW Brown Solar field. Incremental solar generation has been added through the Simpsonville Solar Share facility, which today amounts to 2.1 MW in nameplate AC capacity. The table below shows the Companies' peak hourly load in each winter month (defined as January, February, and December) since December 2016. During these winter peak hours, the Companies' mean solar generation capacity factor is 1.6%, the median is 0.7%, and the mode is 0%.

Date/Time (EST, Hour Beginning)	Peak Hourly Load (MW)	Solar Generation (MW)	Nameplate Capacity (MW)	Capacity Factor (%)
2/3/2023 8:00	4,902	0.2832	12.1	2.3%
1/24/2023 8:00	4,790	0.162	12.1	1.3%
12/23/2022 17:00	6,407	0	12.1	0.0%
2/15/2022 7:00	4,968	0	11.7	0.0%
1/27/2022 7:00	5,539	0	11.7	0.0%
12/20/2021 8:00	4,632	0.0875	11.7	0.7%
2/17/2021 8:00	5,589	0	10.8	0.0%
1/29/2021 8:00	5,264	0	10.8	0.0%
12/2/2020 8:00	4,873	0.0733	10.8	0.7%
2/14/2020 8:00	5,161	0	10.4	0.0%
1/22/2020 7:00	5,317	0	10.4	0.0%
12/19/2019 7:00	5,321	0	10.4	0.0%
2/1/2019 8:00	5,083	0.1	10	1.0%
1/31/2019 8:00	6,234	0.7	10	7.0%
12/11/2018 7:00	5,508	0.1	10	1.0%
2/2/2018 8:00	5,534	0.2	10	2.0%
1/2/2018 8:00	6,699	1.1	10	11.0%
12/28/2017 8:00	5,612	0.6	10	6.0%
2/10/2017 7:00	5,229	0	10	0.0%
1/6/2017 11:00	5,679	0.1	10	1.0%
12/15/2016 7:00	5,813	0	10	0.0%

c. The chart below shows the Companies' projected peak winter day in 2027, which is the first year all proposed solar projects are scheduled to be online. The maximum hourly load for that day is 6,107 MW and the projected solar generation from the Companies' existing and proposed solar sites in that hour is 0 MW.


2027 Projected Winter Peak
MW
7000
6000
5000
4000
3000
2000
1000
0
Peak hour load = 6107.4 MW
Peak hour solar generation = 0 MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Load
Projected Solar Generation

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Question No. 65

Responding Witness: Lana Isaacson / Stuart A. Wilson

Q-65. Refer to LG&E/KU's response to Staff's First Request, Item 53f. Refer also to Wilson Testimony, Exhibit SAW-1, Table 13, page 32.

a. Explain whether all the resources in the Table provided in response to Item 53f are included in column 1 of Exhibit SAW-1, Table 13, with the exception of the Brown BESS and the Mercer and Marion county solar builds. If not, explain the differences.

b. Provide the reserve margin associated with Exhibit SAW-1,Table 13, column 1.

c. Explain whether there are operational services over the course of a year within this portfolio as compared to Table 13 that are greater than the additional costs of adding the Brown BESS and the Mercer and Marion county solar builds.

d. Explain why the Existing Dispatchable DSM decreases every year during the summer.

A-65.

a. Confirmed, with the only other exception being dispatchable DSM. Section 4.6.2 in Exhibit SAW-1, which follows the referenced Table 13, provides the basis for including dispatchable DSM.

b. Dispatchable and total reserve margins in summer and winter are shown in the table below. Dispatchable reserve margins are unchanged from the table provided in response to PSC 1-53(f), as the differences were from intermittent/limited-duration resources only.

Reserve Margin %

	Summer		Winter	
	Dispatchable	**Total**	**Dispatchable**	**Total**
2023	18.2%	23.0%	33.7%	37.4%
2024	18.0%	24.0%	33.9%	37.6%
2025	16.3%	23.7%	25.7%	29.3%
2026	16.2%	30.1%	25.8%	29.5%
2027	19.6%	34.7%	29.3%	32.9%
2028	15.7%	30.9%	25.1%	28.7%
2029	15.9%	31.1%	25.1%	28.7%
2030	16.0%	31.1%	25.2%	28.8%
2031	16.0%	31.1%	25.2%	28.8%
2032	16.1%	31.2%	25.2%	28.8%
2033	16.2%	31.2%	25.1%	28.8%
2034	16.3%	31.3%	25.1%	28.7%
2035	16.4%	31.4%	25.1%	28.7%
2036	16.5%	31.5%	25.0%	28.7%
2037	16.5%	31.5%	25.0%	28.6%
2038	16.6%	31.6%	25.0%	28.6%
2039	16.7%	31.7%	25.0%	28.6%
2040	14.4%	29.4%	22.3%	26.0%
2041	14.4%	29.4%	22.3%	25.9%
2042	14.5%	29.5%	22.3%	25.9%
2043	14.6%	29.6%	22.3%	25.9%
2044	14.7%	29.7%	22.2%	25.8%
2045	14.8%	29.8%	22.2%	25.8%
2046	14.8%	29.9%	22.2%	25.8%
2047	14.9%	29.9%	22.1%	25.8%
2048	15.0%	30.0%	22.1%	25.7%
2049	15.1%	30.1%	22.1%	25.7%
2050	15.2%	30.2%	22.1%	25.7%

c. It is unclear to which "operational services" the request refers. That aside, see the response to part (a). The only other exception is dispatchable DSM.

d. See the response to JI 1-75.

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Question No. 66

Responding Witness: Stuart A. Wilson

Q-66. Refer to LG&E/KU's response to Staff's First Request, Item 57.

a. Provide the effective load carrying capability (ELCC) values for each of LG&E/KU's existing units, the proposed NGCC units, the four proposed solar PPAs, and the Mercer and Marion solar facilities.

b. Confirm that LG&E/KU's response to Item 57e is stating that there were no transmission costs included in the PLEXOS modeling (Stage One, Step One) or the PROSYM modeling (Stage One, Step Two).

A-66.

a. The Companies have not calculated ELCC values for any of their existing or proposed units. The Companies are not aware of cases where ELCC is computed for thermal resources. The capacity contributions computed for limited-duration resources (i.e., dispatchable DSM and battery storage) are similar to ELCC, but the calculation is not the same. See the response to Question No. 81. For capacity contribution by resource type, see the response to PSC 1-90(e).

b. Not confirmed. The Companies' response to PSC 1-57(e) states, "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." See the response to Question No. 53(b) for an explanation regarding how these transmission costs were incorporated into PLEXOS and the Financial Model.

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Question No. 67

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

Q-67. Refer to LG&E/KU's response to Staff's First Request, Item 58. Refer also to LG&E/KU's response to the Attorney General's First Request for Information, Item 30(I).

a. If LG&E/KU's proposed portfolio had been in service during winter storm Elliott, explain whether the NGCC units at Brown and Mill Creek stations would have been able to perform without interruption or derated due to fuel supply related issues.

b. Provide a copy of the letter from copy of Texas Gas Transmission describing changes to its operating procedures and upgrades to its system.

c. State whether any of the LG&E/KU's natural gas storage fields have been retired or closed in the last 3 years or will be retired/closed. If so, explain the reasons and how this additional capacity and supply will be replaced.

A-67.

a. The RFP for the construction of the NGCC units instructs bidders to provide compression options, one of which accounts for the conditions experienced during winter storm Elliott. If this option is selected, it will mitigate the natural gas pressure in conditions identical to winter storm Elliott for the proposed NGCC units at Brown and Mill Creek.

b. See attachment to the response to PSC 1-58(a) for the letter from Texas Gas Transmission. Also, the Companies are attaching an April 5, 2023 presentation from the Boardwalk Pipeline (which owns Texas Gas Transmission) customer meeting in Nashville, TN given by Jeff Sanderson, SVP Operations, Engineering, and Construction. Their enhanced winterization investments and actions are described on pages 15-17 of the pdf.

c. The natural gas storage fields are part of LG&E's gas LDC. LG&E's LDC began the process to retire the Doe Run storage field in 2022. The field is anticipated to be completely closed by the end of 2024. The Doe Run field is no longer economical to operate due to the cost of natural gas lost from the field and incremental investment required to maintain reliable operation. The capacity and supply have been replaced by purchasing short term firm ("STF") pipeline service from Texas Gas Transmission. LG&E has no plans to retire any other storage fields.

The attachment is being provided in a separate file.

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Question No. 68

Responding Witness: Lana Isaacson

Q-68. Refer to LG&E/KU's response to Staff's First Request, Item 70.

a. Confirm that once the customers complete the installation of the audit kits and fill out the rebate forms that LG&E/KU will engage with a third party to ensure completion of the audit kits before issuing the rebate.

b. Explain whether LG&E/KU are aware of any upfront costs for engaging in a third-party vendor to ensure of the audit kits competition.

A-68.

a. Confirmed. The third party will spot check certain rebate items to validate that rebated items adhere to the program's rules for eligibility and detect fraudulent applications.

b. The Companies are not yet aware of any upfront costs as they have not yet issued an RFP for these services.

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Question No. 69

Responding Witness: John Bevington

Q-69. Refer to LG&E/KU's response to Staff's First Request, Item 72. Explain whether LG&E/KU would consider implementing a DSM/EE program if the DSM/EE program had substantial capacity savings but is barely considered not cost-effective.

A-69. Yes.

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Question No. 70

Responding Witness: Lana Isaacson

Q-70. Refer to LG&E/KU's response to Staff's First Request, Item 74b and c.

a. LG&E/KU states that 53 percent of industrial customers elected to opt-out of the DSM/EE programs but that LG&E/KU do not record the reasons for opting out. Explain the process for how a participant opts out of a DSM/EE program and the reasons why LG&E/KU do not ask why industrial customers are opting out.

b. Explain the impact participation levels have on DSM/EE programs when considering cost-effectiveness.

A-70.

a. An industrial or energy-intensive customer provides an executed opt-out form to the Companies if they elect to opt-out of the Companies' DSM programs and recovery mechanism. This election is effective in the next billing cycle. The opt-out form states that the customer has or is implementing cost-effective energy efficiency measures on their own. The customer's signature attests to this explanation for electing to opt-out.

b. The participation levels are a component of the overall avoided energy and/or avoided capacity benefits of a program. There are three cost-effectiveness tests where the numerator is partly based on the avoided energy and avoided capacity costs: TRC, PAC, and RIM. The denominator of these tests is, in part, the program costs. A higher numerator that is a result of greater avoided energy and/or capacity costs generated from higher participation with little to no change in the denominator will improve the cost-effectiveness value.

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Question No. 71

Responding Witness: Stuart A. Wilson

Q-71. Refer to LG&E/KU's response to Staff's First Request, Item 87. Given the relatively low cost of an SCCT resource in the current analysis, explain why this resource was not selected in LG&E/KU's initial PLEXOS modeling runs. Include a comprehensive description of factors that led to this outcome, including all modeling assumptions that either limited SCCT selection or promoted/required NGCC selection.

A-71. While SCCT resources have a relatively low construction cost, SCCT resources have significantly higher energy costs than NGCC resources. The retiring coal units, particularly Mill Creek 2 and Ghent 2, operate at high capacity factors and generated 15 percent to 18 percent of the Companies' total energy from 2017 to 2021.[25] The loss of this generation must be replaced either with existing resources (which are already operating at relatively high capacity factors) or new resources. Among new resources, NGCC capacity is the most cost-effective resource for operating at high capacity factors and producing energy during both daylight and nighttime hours.

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[25] See Mr. Sinclair's Direct Testimony, Table 1.

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Question No. 72

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

Q-72. Refer to LG&E/KU's response to Staff's First Request, Item 92, which discussed how including carbon capture and sequestration (CCS) in NGCC resource evaluation differed from the 2021 IRP and this proceeding. State whether SCCT would be the preferable option if NGCC was found to require CCS.

A-72. As stated in response to PSC 1-92(a), no RFP response was received that included an NGCC with CCS. Therefore, is it not possible to answer this question based on known information. Furthermore, the potential answer to the question would likely depend on the specifics of the CCS requirement, the amount of CO_2 required to be captured, and the timing of compliance. The answer would also depend on any CO_2 limitations associated with SCCT.

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Question No. 73

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

Q-73. Refer to LG&E/KU's response to Staff's First Request, Item 104.

a. Provide a map of the Texas Gas Transmission pipeline showing the zones and the major receipt and delivery points.

b. Provide a map of the Texas Eastern and Tennessee Gas pipelines showing the zones and the major receipt and delivery points.

c. Identify the points at which LG&E/KU expect to take delivery of gas from the pipeline for its proposed NGCC Units from each of the pipelines.

d. Identify the points at which gas purchased by LG&E/KU for electric generation and transported on the Texas Gas Transmission, Texas Eastern, or Tennessee Gas pipeline has been received onto each pipeline in each of the last 3 years and the quantities of gas received at each such point.

e. Explain and provide any analysis performed by LG&E/KU regarding whether there will be sufficient capacity on the Texas Gas Transmission or Tennessee Gas pipelines to serve existing gas units, the proposed NGCC units, and gas units being proposed by other utilities.

A-73.

a. See attached.

b. See attached.

c. The approximate locations of the interconnection points for the pipelines serving the proposed NGCCs are identified on the maps provided in parts (a) and (b).

d. The Companies purchase "delivered gas" from marketers with contracted capacity on the Texas Eastern and Tennessee Gas pipelines and do not have access to information identifying the points where the gas is received on those pipelines. The following table identifies the amounts of gas received in each zone on the Texas Gas Transmission system for the prior 3 years.

Texas Gas Zone Receipts (in MMBtu)			
Year	ZONE SL	ZONE 1-ML	ZONE 3
2020		37,942,011	
2021	130,000	43,124,023	15,000
2022		52,821,543	1,603,170
Total	**130,000**	**133,887,577**	**1,618,170**

e. The Companies confirmed with Texas Gas Transmission and Tennessee Gas Pipeline that sufficient firm transport capacity was available for the Companies' proposed NGCC units. Capacity on Texas Eastern Transmission is available only through marketers holding that capacity. The Companies do not have information on units proposed by other utilities.

The attachments are being provided in separate files.

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Question No. 74

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

Q-74. Refer to LG&E/KU's response to Staff's First Request, Item 104 and Item 105. Refer also to North American Electric Reliability Corporation (NERC) Contingency Reserves, available at www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf.

a. Provide the summer and winter installed capacity (ICAP) and unforced capacity (UCAP) values for Cane Run 7, Paddy's Run, and the Trimble County SCCTs.

b. State whether the addition of the proposed Mill Creek NGCC unit would make the loss of the Texas Gas Transmission pipeline the most severe single contingency on LG&E/KU's system and in its Balancing Area, and explain each basis for LG&E/KU's response.

c. State whether the addition of the proposed Mill Creek NGCC unit would affect the amount of contingency reserves LG&E/KU must maintain and explain each basis for LG&E/KU's response.

d. Given LG&E/KU's current reliance on the Texas Gas Transmission pipeline and the availability of two pipelines to serve the proposed Brown NGCC unit, explain why LG&E/KU selected building an NGCC unit at Mill Creek instead of Brown in the event that SCR was added to Ghent Unit 2 and only a single new NGCC unit was selected.

A-74. The referenced NERC Standard BAL-002-WECC-3, titled "Contingency Reserve," applies to the Western Interconnect.[26] For the Eastern Interconnect, BAL-002-3 is titled "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event."[27] The purposes of the two BAL NERC standards differ. The WECC standard's purpose is "[t]o specify the

[26] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf
[27] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf

quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions." BAL-002-3's purpose is "[t]o ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event."

a. See the response to PSC 1-89(c).

b. No, it would not. NERC defines "contingency" for all of its standards as, "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."[28] Fuel transportation services such as pipelines, barges, rail, and truck do not fall under this definition.

c. Contingency reserve requirements would not be affected. The Companies are members of a reserve sharing group which bases the amount of reserves on a load ratio share of the largest Most Severe Single Contingency ("MSSC") of the group. The current MSSC is a TVA unit rated at 1,347 MW.

d. See the response to Question No. 15(c).

[28] NERC Glossary of Terms definition of Contingency, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, page 10.

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Question No. 75

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

Q-75. Refer to the LG&E/KU's response to Sierra Club's Initial Request for Information, Item 13.

a. Provide a detailed, itemized breakdown of what costs are included in the Capital Expenditures, Fixed O&M, and Variable O&M for Mill Creek NGCC and Brown.

b. Explain how these costs are connected to the PLEXOS input files such as:

(1) Variable_OM_NewGas.csv;
(2) CONFIDENTIAL\FOM_22RFP_AssetsInclBuildCostECC.csv;
(3) AnnualCosts.csv; and
(4) Any other files used to model these costs.

c. State whether the Capital Expenditures cost include transmission costs such as voltage support.

d. State whether a transmission analysis has been performed to assess whether other portfolio decisions (new build or retirement) could impact the need for voltage support at the siting of potential NGCC builds, and if so, provide the transmission analysis.

A-75.

a. See attached. Certain information from Attachment 1 and all the information from Attachments 2-4 are confidential and proprietary and are being provided under seal pursuant to a petition for confidential protection. Attachment 1 includes a high-level breakdown of the various cost components included in the cost categories in the Companies' response to SC 1-13. Attachment 2 shows how the Engineering, Procurement, and Construction (EPC) Contract, Owner Development, and Owner Execution costs are allocated across the project timeline, while Attachments 3 and 4 include the detailed, itemized breakdown of these components of the respective Mill Creek and Brown NGCC bids.

b.

(1) The Variable_OM_NewGas.csv file includes the NGCC units' costs for the Long-Term Service Agreement (LTSA) capital and O&M, SCR consumables, and other variable O&M.

(2) The CONFIDENTIAL\FOM_22RFP_AssetsInclBuildCostECC.csv file includes the economic carrying charge for the revenue requirements associated with construction capital expenditures (EPC Contract, Owner Development, and Owner Execution), ongoing fixed O&M (labor, spare parts, fixed maintenance parts and labor, and miscellaneous expenses), and firm gas transportation for the proposed Mill Creek and Brown NGCC units.

(3) The AnnualCosts.csv file does not include costs for the proposed Mill Creek and Brown NGCC units. It includes the stay-open costs for existing units only.

(4) The BuildCost_GasTransmission.csv file includes the present value of the revenue requirements for the capital costs of transmission system upgrades associated with the proposed Mill Creek and Brown NGCC units. See the responses to part (c) and to Question No. 53(b) for details regarding these costs.

c. Capital expenditures from the referenced table reflect interconnection costs associated directly with the NGCC units but exclude transmission system upgrade costs. However, the CPCN analysis includes transmission system upgrade costs referenced in section 7.6 of Exhibit SAW-1.

d. Yes, see "\04_FinancialModel\Support\TransmissionCapital\CONFIDENTIAL_Generation Replacement Scenarios - Impacts on the Transmission System_2022.docx" in Exhibit SAW-2. When any transmission analysis is performed to identify transmission system upgrades, both thermal loading and voltage support are analyzed.

The attachment is being provided in a separate file.

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Question No. 76

Responding Witness: Lonnie E. Bellar

Q-76. Refer to LG&E/KU's response to the Attorney General's Initial Requests for Information, Item 13, Attachment 1. Given that the proposed Mill Creek NGCC will be served by the Texas Gas Transmission pipeline, and LG&E/KU have not investigated providing a second gas supply source to the proposed plant, explain how the inability of the Texas Gas Transmission pipeline to meet the contractual delivery obligations during Winter Storm Elliot factors into the firm capacity rating of the Mill Creek NGCC.

A-76. See the responses to Question No. 67(a) and (b).

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Question No. 77

Responding Witness: Stuart A. Wilson

Q-77. Provide the methodology used to justify a 100 percent firm capacity rating for the NGCC and SCCT plants for calculating minimum reserve margin, and any supporting workpapers.

A-77. The Companies' minimum reserve margin targets determine the minimum level of reserves on a net capacity (ICAP) basis needed to address both the risk of forced outages as well as the uncertainty associated with extreme weather events. In the SERVM analysis to determine these targets, the Companies use the seasonal ICAP ratings for thermal units to model their generation portfolio over 49 weather and load scenarios and 300 unit availability scenarios. This approach properly considers, for example, the likelihood and impact of partial outages and multi-unit outages. Minimum reserve margin targets are inputs to the Companies' portfolio screening analysis in PLEXOS where thermal resources are also modeled based on seasonal ICAP ratings and a forced outage rate. Ultimately, the justification for a 100 percent firm capacity rating for thermal units is to properly determine minimum reserve margin targets that are appropriate for use in PLEXOS.

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Question No. 78

Responding Witness: Tim A. Jones

Q-78. Provide the total existing distributed generation capacity in LG&E/KU's territory including battery energy storage.

A-78. See the table below. The data reflects battery and solar installed capacity as of March 31, 2023.

Total Distributed Generation Capacity (kW)		Total Distributed Battery Storage (kW)	
Solar[29]	Wind or Hydro	Paired with Distributed Generation	Not Paired with Distributed Generation
44,816	75.2	1,781	Unknown

[29] The figures include Net Metering and Qualifying Facilities customers. The figures also include ODP.

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Question No. 79

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

Q-79.

a. Describe the firm gas transmission capacity required to supply the proposed new NGCC units to ensure firm generation capability.

b. Provide the incremental firm gas delivery required (e.g., Dth/day) for each new unit.

c. Provide the firm gas transport already secured by LG&E/KU, identifying the corresponding pipelines, and any new incremental gas deliverability required to ensure firm supply to these new units.

A-79.

a. See the response to part (b).

b. Based on the heat rate and capacity engineering estimates, the Companies anticipate an incremental firm gas need of approximately 94,000 Dth/day per NGCC unit. Preliminary discussions with pipeline operators have assumed an incremental firm gas need of 100,000 Dth/day per NGCC unit.

c. No firm gas transport will be acquired prior to Commission approval of the new NGCC units.

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Question No. 80

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

Q-80. Explain the reasoning behind including a carbon price adder in production cost modeling, but not including it in any of the capacity expansion steps.

A-80. As discussed in pages 8 and 9 of Mr. Imber's direct testimony, the Companies do not believe any federal CO_2 pricing regime is likely in the near term. Therefore, the Companies developed the optimal portfolio based on current CO_2 regulations (i.e., zero CO_2 price) and then stress-tested that portfolio with a CO_2 price. Despite not using a CO_2 price in the initial portfolio optimization process, as shown in Table 14 of Exhibit SAW-1, Portfolio 1 has the lowest CO_2 emissions compared to the other portfolios. The addition of the Companies-owned solar projects only further decreases emissions. Also, as shown in Table 14, the stress-testing analysis demonstrated that the optimal portfolio using no CO_2 price has the most flexibility in reducing CO_2 emissions if CO_2 pricing is introduced at a later date. Any CO_2 pricing regime would have significant effects across the Companies' generation fleet, likely leading to additional coal retirements and a greater need for lower-CO_2-emitting baseload resources such as NGCC.

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Question No. 81

Responding Witness: Stuart A. Wilson

Q-81. Refer to Wilson Testimony, Exhibit SAW-1, 2022 Resource Assessment, Exhibit SAW-1, pages 22–23, section 4.4.1 "Stage One, Step One: Portfolio Development and Screening with PLEXOS," which describes the initial capacity expansion modeling performed in PLEXOS. Provide the results of additional PLEXOS modeling runs using identical assumptions to those used in Stage One, Step One as described in the 2022 Resource Assessment, with only the following modifications:[30]

a. Capacity contribution of new thermal resources:

(1) The assumed capacity contribution of each new thermal resource option should not equal 100 percent of its nameplate value and should instead be updated to equal the resource's correct ELCC value (i.e., accounting for historical performance and unforced outages).

(2) If LG&E/KU has not performed any analysis to determine the correct ELCC value of new thermal resources, the seasonal UCAP value should be used instead. If the seasonal UCAP values are also not known, an ELCC value of 90 percent should be used.

(3) If LG&E/KU has not yet conducted analysis to determine the correct ELCC values of its thermal resources, i.e. using the SERVM model, then this analysis should be conducted in parallel to this request for additional model runs.

b. Book life of new thermal resources:

(1) New CC or CT units should assume a book life of 20 years to correspond to a net-zero by 2050 framework.

[30] If LG&E/KU cannot complete the modeling runs by May 4, 2023, LG&E/KU may file a motion requesting an extension and providing the estimated date this response will be filed.

(2) Additional resource options can be added to reflect a 35-40 year book life for new CC or CT units, but these options should also be updated to include the incremental capital costs of either CCS or green H2, including production, transportation, and storage.

c. Availability of new solar and storage resources:

(1) Each of the RFP responses should be made available for selection by the model as a capacity resource

(2) The Brown BESS should be made available for selection by the model as a capacity resource

d. Build Constraints:

(1) Remove all constraints that require a CC unit to be built on or before any date the model selects for a coal unit to be retired. For example, new builds should be driven by portfolio-level reserve margin requirements, not specific unit retirements.

(2) Remove all constraints for the order of CCs to be built. For example, some of the new resource options appear to include a required sequence of additions, such as "NewGas_MCbeforeBR_CC", "NewGas_MCbeforeBR_CT".

e. Coal Unit operations options:

(1) For the Mill Creek and Ghent coal units, the additional options should be included in addition to retirement and SCR installation. This should include:

(a) Seasonal operation whereby generation is limited to only months outside of the ozone season.

(b) Mothballing the units such that they could return to operation at a later date depending on how LG&E/KU's needs evolve.

(2) For each coal unit retirement date, ensure that retirement is an option the model can select in any year rather than a pre-specified subset of years.

A-81. Regarding the premises of this request:

- The Companies disagree with the assertion that the assumed capacity contribution for thermal resources should be anything but 100 percent.

The capacity contributions computed for limited-duration resources in Exhibit SAW-1, Appendix D are similar to the effective load carrying capability (ELCC) that RTOs compute for limited-duration resources, but the calculation is not the same. Capacity contribution for a limited-duration resource is computed as the ratio of the resource's impact on LOLE to the LOLE impact of a like-amount of SCCT capacity. Based on this calculation, the capacity contribution for a SCCT would be 1 (i.e., 100 percent). The capacity contribution for other thermal resources should also be 100 percent because differences in availability are modeled using unit-specific forced outage rates.

- The Companies do not believe the use of UCAP capacity ratings in PLEXOS is appropriate. The minimum capacity requirements in PLEXOS are determined as a function of the Companies' peak demand and their minimum reserve margin targets, which are developed in part to address the risk of forced outages (see the response to Question No. 77). The use of UCAP capacity ratings will artificially increase the amount of capacity needed to meet minimum reserve margin targets.

- The Companies are not aware of cases where ELCC is computed for thermal resources. For example, according to PJM's "December 2022 Effective Load Carrying Capability (ELCC) Report," PJM uses the ELCC methodology to calculate the ELCC Class Ratings for ELCC Classes, which consist of "Onshore Wind, Offshore Wind, Solar Fixed Panel, Solar Tracking Panel, 4-hr Energy Storage, 6-hr Energy Storage, 8-hr Energy Storage, 10-hr Energy Storage, Solar Hybrid Open Loop, Solar Hybrid Closed Loop, Intermittent Hydropower, Landfill Gas Intermittent, Hydro with Non-Pumped Storage."[31] In PJM's ELCC analysis, "Thermal Unlimited Resources," which include NGCC and SCCT, are modeled via Monte Carlo using forced outage metrics.[32] This approach is similar to the approach used in SERVM to develop capacity contributions for limited-duration resources and minimum reserve margin targets. Based on this understanding, the Companies have not tried to compute ELCC values for thermal resources. UCAP would provide a reasonable estimate of ELCC for thermal resources, but UCAP should not be used in the Companies' modeling.

- The Companies disagree with the assertion that a 20-year book life for CC or CT units is needed to "correspond to a net-zero by 2050 framework." As noted in the PPL Climate Assessment Report on page 23, "We view our path to net-zero emissions on a continuum, with a primary focus on

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[31] See the following report at page 1 (pdf page 4): https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx.
[32] *Id.* at 3.

eliminating our gross emissions, leveraging technology to remove emissions where they cannot be eliminated due to cost or reliability constraints, and finally, considering carbon offsets for any remaining emissions as the least-preferred option."[33]

- For the reasons stated in the response to Question No. 15(c), the Companies believe the removal of the constraint that requires the first NGCC to be constructed at the Mill Creek Station is not appropriate.

  Notwithstanding these comments, the Companies have completed the model run as requested. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The results are presented below with the following notes:

- The Companies did not receive RFP responses for NGCC or SCCT that included costs for CCS or green hydrogen. Therefore, these resources were not modeled.

- Regarding the availability of new solar and storage resources, the Companies included all the proposals for Companies-owned solar and BESS that were originally excluded in the Stage One and Stage Two analyses.

- Regarding build constraints, the order requiring gas-fired resources to be constructed at Mill Creek before constructing at Brown was removed. Because the transmission system upgrade cost is dependent on the final system configuration, not specific resource decisions, the average transmission system upgrade cost was assigned to new Mill Creek and Brown gas-fired resources equally.

- Regarding coal unit operations, the options to operate Mill Creek 2 or Ghent 2 without SCR but only in non-ozone season months was included as an additional resource alternative.

The resulting portfolios include:

- continuing to operate Ghent 2, but in non-ozone-season months only (October through April),
- retiring Mill Creek 2 and Brown 3,
- constructing two 250 MW combustion turbines at Mill Creek,
- 100 MW battery storage PPA, and

[33] Energy Forward, PPL's 2021 Climate Assessment Report, page 23.

- between 518 MW and 2,772 MW of solar PPAs, depending on the fuel price scenario.

The following table summarizes the resulting portfolios by fuel price scenario.

	Fuel Price Scenario (Gas, CTG Price Ratio)	**GH2 non-ozone operations only**	**Retire MC2 & BR3**	**Add 2 CTs at Mill Creek**	**Solar PPAs Added (MW)**	**Storage Added (MW)**
Expected	Low Gas, Mid CTG Ratio	X	X	X	518	100
	Mid Gas, Mid CTG Ratio	X	X	X	737	100
	High Gas, Mid CTG Ratio	X	X	X	1,622	100
Atypical CTG	Low Gas, High CTG Ratio	X	X	X	599	100
	High Gas, Low CTG Ratio	X	X	X	1,422	100
	High Gas, Current CTG Ratio	X	X	X	2,772	100

The results with these assumptions are unsurprising. Accelerating the depreciation of NGCC and SCCT to 20 years has a greater impact on the cost of NGCC (40-year book life) than the cost of SCCT (30-year book life). As a result, these portfolios include SCCTs for year-round capacity and rely on the remaining coal and NGCC resources for energy more heavily than today. In the summer, with Ghent 2 not in operation, the portfolio relies on solar PPAs and battery storage for capacity, albeit intermittent and limited-duration. The following table summarizes these portfolios' 2028 reserve margins. It demonstrates that, while these portfolios meet minimum reserve margin targets, they do so with a much smaller proportion of fully dispatchable resources, which creates additional reliability risks compared to the Companies' proposed portfolio.

		Summer Reserve Margin		Winter Reserve Margin	
	Fuel Price Scenario (Gas, CTG Price Ratio)	**Fully Dispatchable**	**Total**	**Fully Dispatchable**	**Total**
Expected	Low Gas, Mid CTG Ratio	3.8%	18.3%	20.5%	25.4%
	Mid Gas, Mid CTG Ratio	3.8%	21.0%	20.5%	25.4%
	High Gas, Mid CTG Ratio	3.8%	32.0%	20.5%	25.4%
Atypical CTG	Low Gas, High CTG Ratio	3.8%	19.3%	20.5%	25.4%
	High Gas, Low CTG Ratio	3.8%	29.5%	20.5%	25.4%
	High Gas, Current CTG Ratio	3.8%	46.3%	20.5%	25.4%

The attachment is being provided in a separate file.