COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE GREEN RIVER GENERATING STATION AND A SOLAR PHOTOVOLTAIC FACILITY AT THE E.W. BROWN GENERATING STATION	**)))))))))**	**CASE NO. 2014-00002**

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY
TO THE SECOND SET OF DATA REQUESTS OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
DATED APRIL 10, 2014

FILED: APRIL 24, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs for LG&E and KU Services Company, 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.

Gary H Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of April 2014.

Susan M. Watkins (SEAL)

Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
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, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of April 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Edwin R. Staton**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 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.

Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of April 2014.

(SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Chief Operating Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 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.

Paul W. Thompson
Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of April 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 1

Witness: David S. Sinclair

Q.2-1. Please provide the first full year expected revenue requirement associated with the Brown Solar Facility. Please break out each component of the revenue requirement such as return, depreciation, fixed O&M, etc.

A.2-1. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 2

Witness: David S. Sinclair

Q.2-2. Please provide the expected revenue requirement associated with the Brown Solar Facility for each year of the first ten years of its expected operation. Please break out each component of the revenue requirement such as return, depreciation, fixed O&M, etc.

A.2-2. See response to Question No. 1.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 3

Witness: David S. Sinclair

Q.2-3. Please provide the most recent forecasted value of RECs expected to be produced by the Brown Solar Facility for each of the first ten years of its expected operations. Since the value of RECs are state specific, please indicate where the RECs are projected to be sold.

A.2-3. The Companies do not have an updated 10-year forecast for solar RECs. In Exhibit DSS-1, the 2016 price of solar RECs was assumed to equal the then current market price in Ohio for solar RECs from Kentucky. Then, this value was assumed to escalate at 2% per year (see Exhibit DSS-1 at page 44). As of April 10, 2014, the market price in Ohio for solar RECs from Kentucky was $55 to $65 per REC.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 4

Witness: David S. Sinclair

Q.2-4. Please provide the first full year expected revenue requirement associated with the proposed Green River NGCC including gas pipeline costs and costs of electric transmission line upgrades. Please break out each component of the revenue requirement such as return, depreciation, fixed O&M, etc.

A.2-4. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 5

Witness: David S. Sinclair

Q.2-5. Please provide the expected revenue requirement associated with the proposed Green River NGCC for each year of the first ten years of its expected operation including gas pipeline costs and costs of electric transmission line upgrades. Please break out each component of the revenue requirement such as return, depreciation, fixed O&M, etc.

A.2-5. See response to Question No. 4.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 6

Witness: David S. Sinclair

Q.2-6. For each year 2008-2013, please provide the gross and net generation from the retired Tyrone 3.

A.2-6. See attached.

Station	**Unit**	**Gross Generation (MWh) 2008**	**Gross Generation (MWh) 2009**	**Gross Generation (MWh) 2010**	**Gross Generation (MWh) 2011**	**Gross Generation (MWh) 2012**	**Gross Generation (MWh) 2013**
Tyrone	3	386,021	27,307	151,172	25,392	0	0

Station	**Unit**	**Net Generation (MWh) 2008**	**Net Generation (MWh) 2009**	**Net Generation (MWh) 2010**	**Net Generation (MWh) 2011**	**Net Generation (MWh) 2012**	**Net Generation (MWh) 2013**
Tyrone	3	355,632	23,524	137,157	22,022	(1,309)	(114)

Negative net generation is reported for 2012 and 2013 since Tyrone 3 was using power for its aux load (building lights, pumps, fans, controls, etc.) eventhough it was not generating any power.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 7

Witness: David S. Sinclair

Q.2-7. For each year 2008-2013, please provide the gross and net generation from the Cane Run coal units to be retired in 2015.

A.2-7. See attached.

Station	Unit	Gross Generation (MWh) 2008	Gross Generation (MWh) 2009	Gross Generation (MWh) 2010	Gross Generation (MWh) 2011	Gross Generation (MWh) 2012	Gross Generation (MWh) 2013
Cane Run	4	1,133,170	1,031,773	1,011,086	1,051,024	717,799	765,014
Cane Run	5	957,543	1,034,752	1,206,997	1,035,301	1,014,303	948,907
Cane Run	6	1,620,771	1,464,510	1,341,111	1,404,308	1,198,072	1,105,565

Station	Unit	Net Generation (MWh) 2008	Net Generation (MWh) 2009	Net Generation (MWh) 2010	Net Generation (MWh) 2011	Net Generation (MWh) 2012	Net Generation (MWh) 2013
Cane Run	4	1,042,427	947,128	927,127	967,087	653,192	696,743
Cane Run	5	883,495	952,330	1,110,385	952,048	928,589	864,302
Cane Run	6	1,477,446	1,335,527	1,233,866	1,287,984	1,084,657	995,291

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 8

Witness: David S. Sinclair

Q.2-8. For each year 2008-2013, please provide the gross and net generation from the Green River coal units to be retired in 2015.

A.2-8. See attached.

Station	Unit	Gross Generation (MWh) 2008	Gross Generation (MWh) 2009	Gross Generation (MWh) 2010	Gross Generation (MWh) 2011	Gross Generation (MWh) 2012	Gross Generation (MWh) 2013
Green River	3	411,258	236,352	374,413	359,232	296,201	338,461
Green River	4	628,552	443,559	588,097	498,513	683,341	703,725

Station	Unit	Net Generation (MWh) 2008	Net Generation (MWh) 2009	Net Generation (MWh) 2010	Net Generation (MWh) 2011	Net Generation (MWh) 2012	Net Generation (MWh) 2013
Green River	3	379,545	216,618	345,263	329,516	270,552	310,970
Green River	4	582,590	408,851	544,049	458,964	635,128	652,894

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 9

Witness: Paul W. Thompson

Q.2-9. KIUC Q1-6 requested all correspondence, emails or other documents in the possession of either Mr. Thompson or Mr. Sinclair that relate in any way to the decision to construct the Green River combined cycle plant or the Brown solar facility. However, no correspondence, emails or other documents from either Mr. Thompson or Mr. Sinclair to the CEO of LG&E/KU, any LG&E/KU Board members or any officials at PPL were provided. Please provide such documents or confirm that they do not exist.

A.2-9. The documents referenced do not exist.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 10

Witness: David S. Sinclair

Q.2-10. Please refer to your response to KIUC Q1-1.

a. When do you expect the dispute resolution proceeding between KU and its 12 municipal customers with a combined load of approximately 440 mw to be completed?

b. What are the main issues in the dispute resolution proceeding?

c. The current municipal contracts have five-year termination notice provisions and the proposed contracts have ten-year termination notice provisions. Is the termination notice provision an issue in the dispute resolution proceeding? If yes, please describe the disagreement.

d. Does the formula rate in the existing municipal contracts assign to the customer as a credit any portion of margins from off-system (non-requirements) sales? If yes, please identify where.

e. Does the formula rate in the proposed municipal contracts assign to the customer as a credit any portion of margins from off-system (non-requirements) sales? If yes, please identify where.

f. Please confirm that the Companies are not aware of any RFP issued by any of KU's municipal customers for a new wholesale generation supply. If you are aware, please explain.

A.2-10.

a. Settlement discussions are ongoing and there is no way to predict when they will conclude. Should issues not be resolved in settlement, there is no deadline for FERC to rule on the issues that are litigated.

b. KU has an obligation to maintain confidentiality in the dispute resolution proceedings. All filings in the case, including issues raised by the

Municipal customers, can be found at the link below by searching for docket numbers EL14-5 and ER14-2428:

http://elibrary.ferc.gov/

c. See the response to subpart b above and the response to AG 2-13.

d. Yes. See tab A-2 in the formula rate.

e. Yes. See tab A-2 in the formula rate.

f. See the response to KIUC 1-1(f).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 11

Witness: Paul W. Thompson

Q.2-11. Please refer to the RTO Membership Analysis provided in response to KIUC Q1-2.

a. Does the MISO cost/benefit analysis on page 7 of 10 include as a benefit the cost reduction of not having to carry 258 mw of reserves under the Reserve Sharing Agreement with TVA? Please explain.

b. Does the PJM cost/benefit analysis on page 8 of 10 include as a benefit the cost reduction of not having to carry 258 mw of reserves under the Reserve Sharing Agreement with TVA? Please explain.

c. Does the MISO cost/benefit analysis on page 7 of 10 assume that LG&E/KU would have to carry the same amount of reserve capacity as a member of MISO versus as stand-alone companies? Please explain.

d. Does the PJM cost/benefit analysis on page 8 of 10 assume that LG&E/KU would have to carry the same amount of reserve capacity as a member of MISO versus as stand-alone companies? Please explain.

e. A key assumption on page 2 of 10 is that "LKE would continue to maintain its own capacity to meet a target planning reserve margin established consistently with current processes." If one of the major benefits on membership in PJM is the ability to carry lower reserves than on a stand-alone basis since an individual Load Serving Entity's reserve requirement is determined by its contribution to PJM's five PLC hours, would you agree that the benefits of PJM membership are understated? Please explain your answer.

f. On page 9 the following statement is made: "Moreover, membership in PJM would almost certainly pit LKE interests against those of the traditional PPL companies on matters of significance to all concerned."

Please describe what is meant by this statement and identify the "matters of significance".

A.2-11.

a. Yes, Section 4.2.1 of the RTO Membership Analysis document provides the assumptions made and the estimated benefits that may be derived from a reduction in Operating Reserves for either MISO or PJM membership.

b. Yes, Section 4.2.1 of the RTO Membership Analysis document provides the assumptions made and the estimated benefits that may be derived from a reduction in Operating Reserves for either MISO or PJM membership.

c. Section 3 of the RTO Membership Analysis document states that one of the key simplifying assumptions in the analysis is "LKE would continue to maintain its own capacity to meet a target planning reserve margin established consistently with current processes." This applied to both the PJM and MISO analysis. However, as shown in Section 4.2.1, the reduction in assumed operating reserves does result in a 1% reduction in the calculated target system planning reserve margin and an estimate of the associated value of such reduction.

d. Section 3 of the RTO Membership Analysis document states that one of the key simplifying assumption in the analysis is "LKE would continue to maintain its own capacity to meet a target planning reserve margin established consistently with current processes". This applied to both the PJM and MISO analysis. However, as shown in Section 4.2.1, the reduction in assumed operating reserves does result in a 1% reduction in the calculated target system planning reserve margin and an estimate of the associated value of such reduction.

e. No, we would not agree that the benefits of PJM membership are understated. As stated in the assumptions of the RTO Analysis, we would expect to continue to maintain our own capacity to meet a target planning reserve margin consistent with our current processes to ensure reliable and cost effective capacity and energy for our customers.

f. It is not uncommon for unbundled utilities operating within retail choice states to have views on RTO energy and capacity market design that differ from vertically integrated utilities operating within more traditionally regulated states. The legacy PPL companies within PJM are unbundled and operate within Pennsylvania, which has retail choice. The Companies are vertically integrated and operate in cost based regulated states of Kentucky and the western portion of Virginia. In addition, RTO voting rules generally provide that affiliated entities comprise a single voting member. Because the legacy PPL companies belong to each of the PJM member sectors to which the Companies would need to belong were they to join PJM, the Companies' membership in PJM has stakeholder voting implications that for the most part are not present in the Companies' MISO scenario. Within the context of section 7 of the RTO Membership Analysis entitled "Additional Considerations and Uncertainties," the statement identifies this difference between the two RTO membership scenarios.

"[M]atters of significance" refers to the variety of alternative RTO market design proposals that are routinely considered and voted upon by RTO stakeholders.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 12

Witness: Gary H. Revlett

Q.2-12. Please refer to Exhibit DSS-1. On page 6 the following statements are made. "If a new NGCC unit is constructed at the Green River station in 2018, the Companies would be able to offset the new unit's SO2, NOx and particulate emissions with the retirement of the two remaining Green River coal units. Absent this offset, the Companies would likely be required to install additional emission control equipment on the new unit and the new unit would likely be subject to more stringent emission limits."

a. Please identify the law or rule that governs the referenced offsets.

b. Identify how much in tons and for how long the SO2 offset would be in effect.

c. Identify how much in tons and for how long the NOx offset would be in effect.

d. Identify the particulates that could be offset. How much and for how long would the offset be in effect.

e. Absent the offsets, what additional emission control equipment would be required? How much would the additional equipment cost to build and to operate?

f. Absent the offsets, please identify and describe the more stringent emission limits.

g. If the Green River NGCC is delayed beyond 2018 would the offsets be unavailable? Please explain.

A.2-12.

a. Prevention of Significant Deterioration (PSD) regulations are incorporated into the Kentucky State Implementation Plan (SIP) at 401 KAR 51.017.

b. The project's annual net emissions decrease for SO_2 emissions averages 17,337 tons for the various options being considered. The net emissions decrease will expire 5 years following the actual shutdown date of the coal-fired units.

c. The project's annual net emissions decrease for NO_x emissions averages 667 tons for the various options being considered. The net emissions decrease will expire 5 years following the actual shutdown date of the coal-fired units.

d. The project's annual net emissions decrease for particulate emissions averages 388 tons for the various options being considered. The net emissions decrease will expire 5 years following the actual shutdown date of the coal-fired units.

e. In the absence of netting out of emissions for PSD, the Companies would be required to perform Best Available Control Technology (BACT) analyses for the various emissions. The BACT analysis for PSD would not require additional controls for SO_2 and particulates as the unit is natural gas fired CT technology. If the project exceeded the PSD significant emission rate (SER) for NO_x, the BACT analysis would affect the design of the NGCC unit, likely requiring the addition of an SCR to meet the BACT limit. As the permit application for this project nets out of PSD for NO_x, the Companies did not perform a BACT analysis for NO_x. If for some unforeseen reason the Companies would be required to install SCR on the combustion turbines for the Green River NGCC, the estimated capital cost would increase by approximately $4.7 million. The operating cost increases would largely be the cost of ammonia with an estimated cost of approximately $133,000 per year. When compared to total annual operating costs (excluding fuel) of approximately $23 million, the cost of ammonia would be immaterial.

f. A full BACT analysis process would have to be completed to determine the emission rates associated for any criteria pollutants. Since the net emissions from this project do not exceed the PSD SERs for SO_2, NO_x, and particulates, the associated BACT emission limit was not determined. However from review of a permit issued in Ohio for a similar source that triggered BACT for these pollutants, the emission limits associated with that project were as follows: SO_2 limit of 0.0014 lbs/mmBtu, NO_x limit of 2.0 ppm at 15% O_2, and a PM limit of 10% opacity for a 6-minute average and PM10/PM2.5 limit of 0.0038 lbs/mmBtu.

g. The offsets would be available 5 years beyond the final operation of the coal-fired units.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 13

Witness: David S. Sinclair

Q.2-13. Please refer to Exhibit DSS-1. On page 6 the following statements are made. "As more time elapses following the retirement of the Green River coal units, the ability to obtain an air permit for a new NGCC unit without operating constraints (e.g. annual start limitations) becomes more uncertain. Therefore, the analysis assumed that the Green River unit would be subject to operating constraints if it is commissioned after 2018. Note 10. In this analysis, the NGCC units commissioned after 2018 are limited to 120 starts per year." Operating constraints for a new NGCC commissioned after 2018 are also discussed on page 36 of Exhibit DSS-1.

a. For an NGCC unit commissioned in 2018 or before, what was the assumed limit on the number of starts per year.

b. Please discuss and quantify the added cost of an operating constraint of 120 starts per year.

A.2-13.

a. There was no assumed limit on the number of starts for NGCC units commissioned in 2018.

b. See the table below. The impact of limiting the number of starts for NGCC units varies depending on the scenario. In the Mid CO_2 scenarios with Low or Mid gas prices as well as the Zero CO_2 scenarios with Low gas prices (six scenarios), the annual number of starts never exceeds 120. In the Mid CO_2 scenarios with High gas prices (two scenarios), the annual number of starts exceeds 120 only in the years before CO_2 prices are assumed to take effect. In these eight scenarios, the impact of an annual start limit is not material. In the Zero CO_2 price scenarios with Mid or High gas prices (four scenarios), a limit on the number of starts reduces the ability to cycle NGCC units off overnight and restart them in the morning. On some occasions when load levels are low and the price spread between natural gas and coal is high, cycling NGCC units off overnight can reduce system fuel costs. The Companies have not performed an analysis to quantify the added cost of an operating constraint of 120 starts per year in these scenarios.

	Scenario											
	0C	**0C**	**0C**	**0C**	**0C**	**0C**	**MC**	**MC**	**MC**	**MC**	**MC**	**MC**
	MG	**MG**	**HG**	**HG**	**LG**	**LG**	**MG**	**MG**	**HG**	**HG**	**LG**	**LG**
Year	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**LL**	**BL**	**BL**	**BL**	**LL**
2018	32	41	176	183	20	20	32	41	176	183	20	20
2019	51	59	188	195	19	19	51	59	188	195	19	19
2020	87	101	212	219	19	19	19	19	19	19	19	19
2021	112	123	243	214	19	19	19	19	19	19	19	19
2022	185	194	264	218	19	19	19	19	19	19	19	19
2023	188	195	247	211	19	19	19	19	19	19	19	19
2024	211	220	282	228	19	19	19	19	18	18	19	19
2025	194	213	237	241	20	21	20	21	20	21	20	21
2026	222	246	211	251	18	19	18	19	18	19	19	19
2027	212	216	208	233	18	18	19	18	19	19	19	19
2028	244	211	232	250	21	20	21	20	20	20	21	20
2029	224	252	214	249	19	20	20	20	19	20	20	20
2030	233	251	224	263	19	19	19	19	19	19	19	19
2031	253	262	232	269	19	20	19	20	19	20	19	20
2032	253	242	239	252	19	19	19	19	19	19	19	19
2033	269	260	243	277	19	19	19	19	19	19	19	18
2034	247	238	151	242	19	18	19	18	19	18	21	19
2035	276	250	177	269	20	19	19	19	20	19	19	19
2036	219	274	169	292	20	20	20	20	20	20	20	20
2037	194	282	169	284	21	19	21	19	20	19	21	19
2038	215	256	216	280	20	19	20	19	20	19	20	19
2039	189	257	185	267	18	20	19	20	18	20	19	19
2040	218	273	200	265	20	20	22	20	20	20	22	20
2041	213	266	185	231	19	19	19	19	19	19	19	19
2042	218	263	182	244	19	21	20	19	18	19	19	19

Gas Price: Low (LG), Mid (MG), High (HG); CO_2 Price: Zero (0C), Mid (MC); Load: 2013 LF (BL), Low (LL)

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 14

Witness: David S. Sinclair

Q.2-14. Attachment 1 to PSC-1-34 lists the assumed 2018 NGCC capacity factors under various model runs. The lowest capacity factor in 2019 is 42% for both the High Gas Low Load Zero Carbon scenario and the High Gas Low Load Medium carbon scenario. For each of these two 42% capacity factor scenarios, please identify the number of starts in 2019.

A.2-14. The number of starts in 2019 for both the High Gas-Low Load-Zero Carbon and the High Gas-Low Load-Medium Carbon scenario is listed in the table below. Because CO_2 prices are not assumed to take effect until 2020 in the Mid CO_2 price scenario, the number of starts in both scenarios is the same.

Year	High Gas-Low Load-Zero Carbon	High Gas-Low Load-Medium Carbon
2019	195 starts per year	195 starts per year

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 15

Witness: David S. Sinclair

Q.2-15. Attachment 1 to PSC-1-34 lists the assumed 2018 NGCC capacity factors under various model runs. The highest capacity factor in 2019 is 95% for both the Low Gas Base Load Zero Carbon scenario and the Low Gas Base Load Medium Carbon scenario. For each of these 95% capacity factor scenarios, please identify the number of starts in 2019.

A.2-15. The number of starts in 2019 for both the Low Gas-Base Load-Zero Carbon and the Low Gas-Base Load-Medium Carbon scenario is listed in the table below. Because CO_2 prices are not assumed to take effect until 2020 in the Mid CO_2 price scenario, the number of starts in both scenarios is the same.

Year	Low Gas-Base Load-Zero Carbon	Low Gas-Base Load-Medium Carbon
2019	19 starts per year	19 starts per year

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 16

Witness: Edwin R. Staton

Q.2-16. Please refer to your response to PSC1-29(b). What decommissioning or retirement cost is included in the current depreciation expense associated with Green River units 3 and 4?

A.2-16. The annual net cost of removal depreciation expense associated with Green River units 3 and 4 is approximately $71,000.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 17

Witness: David S. Sinclair

Q.2-17. Please review to your response to Staff 1-21.

a. Have the Companies made any offers to purchase capacity or energy to address needs in 2016 and 2017? If yes, then please provide details of such offers including pricing, counterparty and terms and conditions.

b. Have any companies made any offers to sell to the Companies capacity or energy to address needs in 2016 and 2017? If yes, then please provide details of such offers including pricing, counterparty and terms and conditions.

A.2-17.

a.-b. This question seeks irrelevant information. Nevertheless, as stated in response to PSC 1-21, the Companies are exploring all options for capacity and energy needs in 2016 and 2017, including alternatives from parties that responded to the Companies' September 2012 RFP. Those efforts include ongoing negotiations between the Companies and other parties, but those negotiations are not final and no agreements have been reached. To the extent any negotiations are finalized, the Companies will supplement this response. However, until that happens, the Companies object to providing the requested information on the basis that no final agreements have been reached and divulging the terms of the ongoing negotiations now could be detrimental to the Companies and their customers.

CONFIDENTIAL INFORMATION REDACTED

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 18

Witness: David S. Sinclair

Q.2-18. Please refer to Exhibit DSS-1 page 34. Please provide a complete copy of the proposal from [redacted] identified as "[redacted] 2yr 167 '16 then 2yr 334 '18, GR '20". The Alt ID for this proposal is C55D. If it is not clear from the proposal, please identify the energy and capacity pricing offer by [redacted] in this proposal.

A.2-18. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

CONFIDENTIAL INFORMATION REDACTED

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated April 10, 2014

Case No. 2014-00002

Question No. 19

Witness: David S. Sinclair

Q.2-19. Please refer to DSS-1 Section 4.5.2 Iteration 2- Deferral Considerations. In order for the PVRR of the preferred plan of building the Green River NGCC in 2018 to be economically equal to or worse than a two year delay (until 2020) under "All Scenarios" (Table 27), please identify the amount of capacity that would be needed each year and the energy prices and capacity prices that would be required. The purpose of this question is to identify a "price to beat" from a credit worthy counter-party such that a two-year delay would be in the best interests of ratepayers under "All Scenarios"."

A.2-19. See Table 33 on page 43 of Exhibit DSS-1. Across all scenarios, the most competitive deferral alternative is alternative C54D ([redacted] 2yr 165 '16 then 2yr 330 '18, GR '20). This alternative pairs a "staged" (165 MW in 2016-17 and 330 MWs in 2018-19) [redacted] PPA with a 2x1 NGCC unit commissioned in 2020 at the Green River site. To ensure that power from the [redacted] assets can flow to the Companies' native load during peak operating periods, a $35 million transmission project must be completed. With this cost, the PVRR of this alternative is $38 million more expensive than the least cost alternative (C50A). The PVRR of the capacity payments and imputed debt for alternative C54D is $26 million; even if [redacted] reduced its capacity payment to zero, alternative C54D would not be least cost.

If the imputed debt calculation is adjusted to conform to Exhibit A of the public comments filed by Big Rivers on April 4, 2014, the PVRR of the two alternatives as well as the PVRR of capacity payments and imputed debt for alternative C54D are reduced only slightly. With the imputed debt adjustment specified by Big Rivers, alternative C54D would not be least cost even if [redacted] reduced its capacity payment to zero.

If the operating constraint of 120 starts per year is removed from the 2020 NGCC unit, the PVRR difference between alternatives C54D and C50A is reduced to $5 million. Based on this result, if [redacted] reduced its capacity payment by 21% (from a monthly average capacity payment of \$2.71/kW-month to a monthly average capacity payment of \$2.14/kW-month), the PVRR of the deferral option (C54D) and the least-cost option (C50A) would be the same. Note that there is no guarantee thtat [redacted] would agree to such an arrangement. Furthermore, the Companies would need to revisit the required transmission system upgrades to ensure they could be completed by the summer of 2016. The table below summarizes this information. All workpapers used to prepare this response are included as attachments. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

	Weighted Average PVRR, All Scenarios (2013- 2042, \$M)			
	C50A: [redacted] 2yr 151 '16, GR '18	C54D: [redacted] 2yr 165 '16 then 2yr 330 '18, GR '20	Delta (C54D less C50A)	C54D: Capacity Payment and Imputed Debt
Exhibit DSS-1	32,238	32,276	38	26
With Imputed Debt Adjustment	32,237	32,275	38	25
Without Annual Start Limit	32,237	32,243	5	25