COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR CERTIFICATES OF PUBLIC	**)**	
CONVENIENCE AND NECESSITY AND	**)**	
APPROVAL OF ITS 2016 COMPLIANCE PLAN	**)**	**CASE NO. 2016-00026**
FOR RECOVERY BY ENVIRONMENTAL	**)**	
SURCHARGE	**)**	

KENTUCKY UTILITIES COMPANY

RESPONSE TO THE
COMMISSION STAFF'S INITIAL REQUEST

DATED MARCH 11, 2016

FILED: MARCH 24, 2016

VERIFICATION

COMMONWEALTH OF KENTUCKY	)	
	)	**SS:**
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, 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.

Robt M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Director – Rates 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.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

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 14th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

VERIFICATION

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

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting 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.

Charles R Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is a Senior Vice President, of Gannett Fleming Valuation and Rate Consultants, LLC, 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 J. Spanos
John J. Spanos

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of March 2016.

Cheryl Ann Rutter (SEAL)
Notary Public

My Commission Expires:
February 20, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **R. Scott Straight**, being duly sworn, deposes and says that he is the Director of Project Engineering for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 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.

R. Scott Straight

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is the Vice President, Transmission and Generation Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 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 N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 1

Witness: Robert M. Conroy

Q-1. The Direct Testimony of Robert M. Conroy ("Conroy Testimony"), page 5, states that as to Project 36, "The total expected capital cost of Phase II is $11.9 million (of which KU seeks to recover $5.3 million through the environmental cost recovery ("ECR") mechanism as part of its 2016 Plan Project 36). KU is not seeking operation and maintenance ("O&M") cost recovery through the ECR mechanism for this project. . . ."

a. Explain what costs will be recovered in the $5.3 million.

b. If there are O&M costs, explain the kinds of cost and provide the annual O&M costs not being recovered.

A-1. a. In KU's most recent base rate case (Case No. 2014-00371), KU included capital costs for environmental projects not yet included in an approved ECR plan in its revenue requirement calculation. The $5.3 million referenced above does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the total projected capital investment for the project less the amount projected in the test year ending June 30, 2016. To avoid any form of double recovery, capital expenditures will not flow through the ECR mechanism until the amount in base rates is exceeded.

b. O&M costs related to Phase II will be similar to costs incurred in Phase I which are already being recovered through KU's environmental surcharge and are not distinguishable. KU plans to continue to recover its Brown landfill O&M costs through its environmental surcharge as part of Project 29.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 2

Witness: Robert M. Conroy

Q-2. The Conroy Testimony, page 6, lines 13–16, states that as to Project 37, "KU is not seeking O&M cost recovery through the ECR mechanism for this project. . . ." If there are O&M costs, explain the kinds of cost and provide the annual O&M costs not being recovered.

A-2. No additional O&M costs are anticipated as related to Project 37.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 3

Witness: Robert M. Conroy / R. Scott Straight / Charles R. Schram

Q-3. Refer to the Conroy Testimony, page 8, lines 5–16, as to Project 38. If the additives for Project 38 are different from the additives for Project 35, provide a comparison of additives and costs.

A-3. The additives referenced are different between Project 35 (Ghent pulse jet fabric filters) and Project 38 (supplemental mercury related control technologies). Relative to mercury control, Project 35's additive is Powdered Activated Carbon (PAC), whereas the additives in Project 38 are a proprietary halogenated chemical liquid for injection into the coal feeders and a proprietary organo-sulfide chemical liquid injected into the Wet Flue Gas Desulfurization (WFGD) slurry in the WFGD absorber.

The quantity of each additive used will depend on unit loads, variability of mercury and other constituents in coal, and other generating unit specific factors. Based on actual test results at Trimble County 1, the estimated average cost of PAC is approximately $0.60/MWh, and the use of the supplemental injection liquids into the coal feeders and WFGD absorber is approximately $0.30/MWh. As Charles R. Schram notes in his testimony at pages 21-22 and Exhibit CRS-2 at pages 9-10, use of the Project 38 additives is expected to reduce the need for PAC injection, and the resulting savings are projected to exceed the cost of the project's capital investment in less than five years.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 4

Witness: Robert M. Conroy

Q-4. The Conroy Testimony, page 10, lines 6–9, states that as to Project 39, "The total projected capital cost of these surface impoundment closures is $77.9 million for all three stations (of which KU seeks to recover $77.5 million through the ECR mechanism as part of its 2016 Plan Project 39). KU is not seeking O&M cost recovery through the ECR mechanism for this project. . . ."

a. Explain what costs will be recovered in the $77.5 million.

b. If there are O&M costs, explain the kinds of cost and provide the annual O&M costs not being recovered.

A-4. a. The $77.5 million referenced above does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the total projected capital investment for the project less the amount projected in the test year ending June 30, 2016. See the response to Question No. 1a.

b. Any costs related to groundwater monitoring once the projects are complete are expected to be minimal and will be charged to the accumulated depreciation reserve similarly to other closure costs. Future O&M costs, such as mowing, are not currently known, but are expected to be minimal, and will be recovered through future rate case proceedings where applicable.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 5

Witness: Robert M. Conroy

Q-5. Refer to the Conroy Testimony, page 11, lines 7–10, as to Project 40. The total projected capital cost is $364.2 million for Ghent, but $339.9 million is to be recovered through the ECR mechanism. Explain what costs are to be recovered and what costs are not.

A-5. The $339.9 million referenced above does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the total projected capital investment for the project less the amount projected in the test year ending June 30, 2016. See the response to Question No. 1a.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 6

Witness: Robert M. Conroy

Q-6. Refer to the Conroy Testimony, page 11, lines 10–12, as to Project 41. The total projected capital cost is $105.3 million for Trimble County, but $101.9 million is to be recovered through the ECR mechanism. Explain what costs are to be recovered and what costs are not.

A-6. The $101.9 million referenced above does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the total projected capital investment for the project less the amount projected in the test year ending June 30, 2016. See the response to Question No. 1a.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 7

Witness: Robert M. Conroy

Q-7. Refer to the Conroy Testimony, page 11, lines 12–13, as to Project 42. The total projected capital cost is $101.3 million for Brown, but $98.3 million is to be recovered through the ECR mechanism. Explain what costs are to be recovered and what costs are not.

A-7. The $98.3 million referenced above does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the total projected capital investment for the project less the amount projected in the test year ending June 30, 2016. See the response to Question No. 1a.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 8

Witness: Robert M. Conroy / R. Scott Straight

Q-8. The Conroy Testimony, page 11, lines 19–20, states that as to Projects 40-42, "KU is not seeking O&M cost recovery through the ECR mechanism for these projects. . . ." If there are O&M costs, by project, explain the kinds of costs and provide the annual O&M costs not being recovered.

A-8. Any costs for Projects 40-42 related to groundwater monitoring are expected to be minimal and will be charged to the accumulated depreciation reserve similarly to other closure costs. Future O&M costs include mowing of the CCR pond closure capping systems, as well as the operational cost associated with treating the waters flowing through the new process water systems with chemical to control total suspended solids and pH of the process waters prior to being discharged from the station. These additional O&M cost are not expected to be incrementally significant for the pond closure capping system maintenance, nor for the process water system chemicals needed to precipitate the solids or treat for pH. KU will seek recovery of these costs in future rate case proceedings where applicable.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 9

Witness: Robert M. Conroy

Q-9. Refer to the Conroy Testimony, page 19, line 10, which states that KU is requesting continuation of the 10.00 percent return on equity ("ROE"). Provide, as of December 31, 2015, the debt and capital structure of KU with the weighted cost of capital using 10.00 percent ROE.

A-9. See attached.

KENTUCKY UTILITIES

Adjusted Electric Rate of Return on Common Equity - ECR Plans
As of December 31, 2015

		Balance at 12-31-15 (1)	Capital Structure (2)	EEI (3)	Investments in OVEC and Other (Col 2 x Col 4 Line 4) (4)	Adjustments to Total Co. Capitalization (Sum of Col 3 - Col 4) (5)	Adjusted Total Company Capitalization (Col 1 + Col 5) (6)	Jurisdictional Rate Base Percentage (7)	Kentucky Jurisdictional Capitalization (Col 6 x Col 7) (8)
1.	Short Term Debt	$ 47,997,120	0.95%	$ -	$ (11,602)	$ (11,602)	$ 47,985,518	88.82%	$ 42,620,737
2.	Long Term Debt	2,341,130,602	46.19%	-	(564,124)	(564,124)	2,340,566,478	88.82%	2,078,891,146
3.	Common Equity	2,679,352,744	52.86%	(504,066)	(645,587)	(1,149,653)	2,678,203,091	88.82%	2,378,779,985
4.	Total Capitalization	$ 5,068,480,466	100.000%	$ (504,066)	$ (1,221,313)	$ (1,725,379)	$ 5,066,755,087		$ 4,500,291,868

		Kentucky Jurisdictional Capitalization (8)	Capital Structure (9)	Environmental Surcharge (Col 9 x Col 10 Line 4) (10)	DSM Rate Base (Col 9 x Col 11 Line 4) (11)	Adjusted Kentucky Jurisdictional Capitalization (Col 8 + Col 10 + Col 11) (12)	Adjusted Capital Structure (13)	Annual Cost Rate (14)	Cost of Capital (Col 13 x Col 14) (15)
1.	Short Term Debt	$ 42,620,737	0.95%	$ (8,878,583)	$ (44,207)	$ 33,697,947	0.95%	0.72%	0.01%
2.	Long Term Debt	2,078,891,146	46.19%	(431,686,037)	(2,149,372)	1,645,055,737	46.20%	4.03%	1.86%
3.	Common Equity	2,378,779,985	52.86%	(494,023,033)	(2,459,748)	1,882,297,204	52.85%	10.00%	5.29%
4.	Total Capitalization	$ 4,500,291,868	100.000%	$ (934,587,653)	$ (4,653,327)	$ 3,561,050,888	100.000%		7.16%
5.	Weighted Cost of Capital Grossed up for Income Tax Effect {ROR + (ROR - DR) x [TR / (1 - TR)]}								10.49%

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 10

Witness: John N. Voyles, Jr. / Charles R. Schram

Q-10. Refer to the Direct Testimony of John N. Voyles, Jr. ("Voyles Testimony"). Explain what alternatives were considered, other than for Projects 36 and 42, as compared to the projects being proposed, and by proposed project and alternative(s), provide the results of any present value analysis that was done.

A-10. See the responses below concerning Projects 37-41.

Project 37: Wet Flue Gas Desulfurization Improvements to Ghent Unit 2

See the testimony of R. Scott Straight at pages 4-6, the testimony of Charles R. Schram at pages 19-21, and Exhibit CRS-2 to the testimony of Mr. Schram at pages 4-9. The alternatives considered were: (1) do nothing (comply using dispatch modifications only); (2) modify the Ghent 2 WFGD to improve its SO_2 removal rate (this alternative is Project 37); (3) use reagent to improve SO_2 removal rate; and (4) burn lower sulfur coal in Ghent 2. (See Exhibit CRS-2 at 5-6.) The PVRR analyses conducted under Mr. Schram's supervision demonstrated Project 37 was superior to the reagent and lower-sulfur-coal alternatives on a 30-year analysis, superior to the lower-sulfur-coal alternative on a six-year analysis, essentially equivalent to the reagent alternative on a six-year analysis, and superior to the do-nothing alternative across three gas-price scenarios on a six-year analysis. The following tables showing the results of the cost-benefit analyses are taken from Exhibit CRS-2 at pages 8-9:

Table 4 – Project 37: 30-Year Analysis (PVRR, 2016-2045, $M, 2016 Dollars)

Alternative	Capital Cost	O&M Impact	Fuel Impact	Total PVRR	Difference from Best
Modify Ghent 2 WFGD	8.8	0.0	0.0	8.8	0.0
Reagent	1.8	20.6	0.0	22.4	13.6
Burn Lower Sulfur Coal	0.0	0.0	174.4	174.4	165.6

Table 5 – PVRR of Costs Incurred from 2016 to 2021 ($M, 2016 Dollars)

Alternative	Capital Cost	O&M Impact	Fuel Impact	Total PVRR	Difference from Best
Modify Ghent 2 WFGD	8.8	0.0	0.0	8.8	1.4
Reagent	1.8	5.6	0.0	7.4	0.0
Burn Lower Sulfur Coal	0.0	0.0	47.5	47.5	40.1

Table 6 – Project 37: WFGD Modification Versus Retire/Replace (PVRR of Costs Incurred from 2016 to 2021, $M, 2016 Dollars)

Gas Price	Alternative	System Production Costs	ECR Project Costs	Total	Diff from Best
Low	Do Nothing	4,942	0	4,942	37
	Modify Ghent 2 WFGD	4,896	8.8	4,905	0
Mid	Do Nothing	5,050	0	5,050	48
	Modify Ghent 2 WFGD	4,993	8.8	5,002	0
High	Do Nothing	5,208	0	5,208	68
	Modify Ghent 2 WFGD	5,131	8.8	5,140	0

Project 38: Supplemental Mercury Related Control Technologies for All Ghent Units

See the testimony of Mr. Straight at pages 6-10, the testimony of Mr. Schram at pages 21-22, and Exhibit CRS-2 to the testimony of Mr. Schram at pages 9-10. Because the chemical-injection systems proposed in this project could be used to inject multiple kinds of mercury-reduction additives, there was no need to consider alternatives from a capital-investment perspective. Also, the alternative of doing nothing was not viable because it created a risk of non-compliance with the MATS Rule's mercury-emission restrictions due to the phenomenon of mercury re-emission (see response to Question No. 20 below). The cost-benefit analysis performed under Mr. Schram's supervision demonstrated the proposed capital investments could effectively pay for themselves in less than five years because the new chemical additives are anticipated to achieve mercury-emission reductions sufficient to reduce the consumption of the current main mercury-emission-reduction consumable, powdered activated carbon. The following table showing the results of the cost-benefit analysis is taken from Exhibit CRS-2 at page 10:

Table 8 – Supplemental Mercury Control System (PVRR of Costs Incurred from 2016 to 2021, $M, 2016 Dollars)

	PVRR ($M)	Payback Period (years)
Ghent 1	(1.6)	3.9
Ghent 2	(1.0)	4.6
Ghent 3	(1.8)	3.8
Ghent 4	(2.3)	3.0
Total	(6.7)	

Project 39: Surface Impoundment Closures at the Green River, Pineville, and Tyrone Generating Stations

See the testimony of Mr. Voyles at pages 16-21 and the testimony of Gary H. Revlett at pages 20-21. The alternative to the proposed surface-impoundment closures is to delay the closures and expose KU to increased closure costs in the future. KU did not perform PVRR-related analyses for this project; however, KU has clearly stated why the project is prudent and lowest-reasonable-cost, and therefore is superior to the do-nothing alternative: (1) it minimizes environmental risk; (2) it avoids escalating costs for engineering, construction, and materials; (3) it achieves economies of scale that will result by closing contemporaneously with the CCR-Rule required closures; and (4) it addresses potential changes in state CCR law that could increase closure, monitoring, or maintenance costs. (See Revlett testimony at 20.)

Project 40: CCR Rule Compliance Construction and Construction of New Process Water Systems at the Ghent Generating Station

See the testimony of Mr. Voyles at pages 22-29, the testimony of Mr. Revlett at pages 4-10, the testimony of Mr. Schram at pages 23-24, and Exhibit CRS-2 to the testimony of Mr. Schram at pages 10-13. As the cited portions of the testimony of Messrs. Revlett and Voyles explain, if the CCR Rule ultimately requires the surface-impoundment closures contemplated in this project, as KU expects will indeed be required, there can be no alternative to closing the surface impoundments: they will have to be closed in accordance with the CCR Rule. For that reason, KU did not, and did not need to, consider an alternative to that portion of Project 40.

Regarding the proposed new process-water facilities, KU considered the alternative of retiring the Ghent coal-fired units in 2019 and replacing the retired units with other capacity, which would avoid the need for new process-water facilities. The six-year PVRR analysis performed under Mr. Schram's supervision demonstrated that building the new process-water facilities and continuing to operate the Ghent coal-fired units through the end of 2021 is superior to retiring the units in 2019 by at least $278 million. The following table showing the results of the cost-benefit analysis is taken from Exhibit CRS-2 at page 13:

Table 11 – Project 40: Analysis Results (PVRR of Costs Incurred from 2016 to 2021, $M, 2016 Dollars)

Gas Price	Alternative	System Production Costs	Other Capital and FOM	ECR Project Costs	Replacement Capacity Costs	Total
Low	Retire in 2019	4,896	271	232	683	6,082
	Operate through 2021	4,896	523	386	0	5,805
	Operate through 2021 Less Retire in 2019	(0)	252	154	(683)	(278)
Mid	Retire in 2019	5,116	271	232	683	6,303
	Operate through 2021	4,993	523	386	0	5,903
	Operate through 2021 Less Retire in 2019	(123)	252	154	(683)	(400)
High	Retire in 2019	5,428	271	232	683	6,614
	Operate through 2021	5,131	523	386	0	6,040
	Operate through 2021 Less Retire in 2019	(297)	252	154	(683)	(574)

Project 41: CCR Rule Compliance Construction and Construction of New Process Water Systems at the Trimble County Generating Station

See the testimony of Mr. Voyles at pages 22-31, the testimony of Mr. Revlett at pages 4-10, the testimony of Mr. Schram at pages 24-26, and Exhibit CRS-3 to the testimony of Mr. Schram at pages 6-8. As the cited portions of the testimony of Messrs. Revlett and Voyles explain, if the CCR Rule ultimately requires the surface-impoundment closures contemplated in this project, as KU expects will indeed be required, there can be no alternative to closing the surface impoundments: they will have to be closed in accordance with the CCR Rule. For that reason, KU did not, and did not need to, consider an alternative to that portion of Project 41.

Regarding the proposed new process-water facilities, KU considered two alternatives to constructing new process-water facilities: (1) retiring the Trimble County coal-fired units in 2019 and replacing the retired units with other capacity; and (2) converting the Trimble County coal-fired units to burn natural gas. Both alternatives would avoid the need for new process-water facilities. The 30-year PVRR analysis performed under Mr. Schram's supervision demonstrated that building the new process-water facilities and continuing to operate the Trimble County coal-fired units through the end of 2045 is superior to both alternatives by at least $478 million. The following table showing the results of the cost-benefit analysis is taken from Exhibit CRS-3 at page 8:

Table 5 – Trimble County Retirement Analysis Results (PVRR, 2016-2045, $M, Reflecting Companies' 75% Ownership Share)

Gas Price	Alternative	Prod Costs	Landfill and CCRT	Other Capital and FOM	ECR Project Costs	Replace-ment Capacity Costs	NGCC Capital	NGCC FOM	NG Conversion	Total	Diff from Best
Low	Long Term Operation	2,692	367	1,229	210	0	0	0	0	4,499	0
	Retire TC Coal Units	2,946	116	141	116	367	944	364	0	4,994	495
	Natural Gas Conversion	3,796	116	949	116	0	0	0	0	4,976	478
Mid	Long Term Operation	2,692	367	1,229	210	0	0	0	0	4,499	0
	Retire TC Coal Units	4,112	116	141	116	367	944	364	0	6,160	1,661
	Natural Gas Conversion	5,546	116	949	116	0	0	0	0	6,727	2,228
High	Long Term Operation	2,692	367	1,229	210	0	0	0	0	4,499	0
	Retire TC Coal Units	5,312	116	141	116	367	944	364	0	7,360	2,861
	Natural Gas Conversion	7,346	116	949	116	0	0	0	0	8,527	4,028

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 11

Witness: John N. Voyles, Jr. / Gary H. Revlett

Q-11. Refer to the Voyles Testimony, page 8, regarding the groundwater monitoring and assessment evaluations being conducted at active surface impoundments. When is the groundwater monitoring and assessment required to be completed pursuant to the CCR Rule?

A-11. The CCR Rule requires groundwater monitoring and initial testing be completed by October 17, 2017. Statistical evaluation and additional monitoring requirements extend the deadline a maximum of an additional nine months (July 2018).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 12

Witness: John N. Voyles, Jr.

Q-12. Refer to the Voyles Testimony, page 14, noting that Phase I of the Brown Landfill will be placed in service in 2016. When during 2016 will Phase I of the Brown Landfill be placed in service?

A-12. KU submitted the Construction Progress Report to the Kentucky Division of Waste Management (DWM) on March 11, 2016. This report is one of the final requirements necessary to receive the Operating Permit. Pending review and acceptance of the report by DWM, the Company anticipates the Operating Permit could be issued in one to three months.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 13

Witness: John N. Voyles, Jr.

Q-13. Refer to the Voyles Testimony, page 14, regarding the Brown Landfill.

a. Explain why the Special Waste Landfill permit for the Brown Landfill contains a 10-foot height restriction for each successive phase of lateral expansion.

b. Do any of KU's other landfills that have a Special Waste Landfill permit have similar restrictions?

A-13. a. The landfill at Brown will be constructed on top of the former main ash pond and (KU Project 29) serves as the cap and closure of that pond. In response to data requests from the DWM during the permit application processes, the Permit Branch raised concerns about the stability of the underlying ash in the Main Pond from uneven compaction and settling created by the placement of dry materials on portions of the landfill from the proposed phases of the project. The DWM resolved their concerns by adding the 10 foot height differential requirement between successive phases, such that the landfill might be loaded uniformly over the surface of the old ash pond. Even though the stability analysis in the permit application showed no issues and provided acceptable stability requirements per generally accepted engineering standards, KU accepted the restriction in the permit to allow construction to begin. Prior to and during construction of Phase I, KU installed additional settlement monitors to gather additional data on the underlying ash. A second stability analysis has been performed with a maximum height of 20 feet, and the modeled results indicate a factor of safety of 2.0, which is better than the industry standard of 1.4. KU is currently evaluating the option to submit a minor permit modification to the existing landfill permit to allow an additional 10 foot height difference between successive phases. If approved, the additional 10 feet in Phase I would delay the need to begin placement of materials into Phase II by approximately three years.

b. No other KU landfills have this permit restriction.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 14

Witness: John N. Voyles, Jr.

Q-14. Refer to the Voyles Testimony, page 18, regarding the closure of the three surface impoundments at Green River. Explain why the SO2 pond is capable of being "clean-close," as compared to being capped and closed.

A-14. The SO_2 pond at Green River could also be capped and closed in the same manner as the other two ponds at the site. However, clean closing this pond, as is currently planned, allows KU to beneficially use the CCR from the SO_2 pond as fill material to grade the surface of the remaining two ponds. This reduces the overall amount of virgin materials that would likely need to be harvested and trucked in from an off-site location for the capping and closure of the three ponds necessary to promote storm water run-on and run-off control. Beneficially using on-site CCR materials available on site will reduce the overall cost of the Green River project.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 15

Witness: John N. Voyles, Jr.

Q-15. Refer to the Voyles Testimony, page 23, concerning the closure option under the CCR Rule involving relining and repurposing an impoundment. Provide a detailed explanation of this closure option and what is meant by repurposing the impoundment.

A-15. The CCR Rule allows the use of wet impoundments provided they are designed with the proper liner systems. The relining and repurposing option is a desirable method for a clean closure approach at some of the Companies' sites, like Mill Creek, that have limited real estate available to construct new CCR ponds or process water systems. In a repurposing closure plan, an impoundment is first cleaned of CCR materials per the requirements of the CCR Rule and then lined. The liner design planned by the Companies is typically a 24" layer of clay (or Geosynthetic Clay Liner (GCL)), a Flexible Membrane Liner (FML) and a concrete Fabricform protective cover so the impoundment can be cleaned out in the future as needed without damaging the liner system. This liner system is compliant with the CCR Rule and would allow the repurposed impoundment to be used for CCR with ongoing groundwater monitoring.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 16

Witness: John N. Voyles, Jr.

Q-16. Refer to the Voyles Testimony, page 25, regarding KU's decision to go forward with the decision to close the impoundments at Ghent, Trimble County, and Brown Generating Stations. Has KU quantified the risk of waiting to begin closure activities and construction of the process water systems until the analyses as required by the CCR Rule are completed? If so, provide a copy of that risk analysis.

A-16. KU has not prepared a written quantitative analysis of the risk of delaying surface-impoundment-closure activities or process-water system construction until after a CCR Rule triggering event occurs because the consequences of such delay clearly would be shutting down generating units, a very costly and serious concern for reliability of the system. To reach this conclusion, KU first assessed what process changes would be necessary to close a CCR impoundment and continue operating the generating station. Then KU evaluated the time requirements for design engineering, permitting and approval processes, and finally construction compared against the closure timelines specified by failing one of the requirements prescribed by the CCR Rule that would trigger closure. If KU waited for the analyses (Groundwater studies and Location Restrictions (triggering events)) to mandate the closure of a CCR facility, there would not be adequate time to construct the new process-water systems that are required to allow the surface impoundments to be closed without ceasing CCR production at the site. The process water systems are required to facilitate the waste water stream changes and construction schedules for closure of the CCR impoundments and continue operating the generation station. If KU waited for a triggering event to occur, generation would be placed in jeopardy as the rule requires ponds to stop receiving CCR materials and non-CCR waste streams and requires the start of closure activities six months after the triggering event. In other words, delaying beginning the construction of process-water systems and related surface-impoundment closures until a triggering event occurs could result in some, if not all, of KU's coal units being inoperable for months, if not years. Idling that quantity of generating capacity simultaneously - about 4,000 MW of total coal-fired generation - would severely compromise KU's ability to ensure continuous and reliable service to their customers. It is not clear such a large quantity of replacement capacity would be available for purchase in the wholesale power market, or that KU could continually import the enormous quantity of energy necessary to supply their customers without creating and experiencing transmission constraints.

In terms of the potential financial impact of such delays, the cost-benefit analyses performed by Mr. Schram in his Exhibits CRS-1 (Brown), CRS-2 (Ghent), and CRS-3 (Trimble County) indicate that the cost of replacement capacity - if it were available - during unit shut-downs forced by untimely actions to comply with the CCR Rule could be well in excess of $100 million more than the cost of constructing process-water facilities to ensure the coal-fired units could continue to operate.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 17

Witness: John N. Voyles, Jr.

Q-17. Refer to the Voyles Testimony, Exhibit JNV-6, page 1 of 50. The table designated as Exhibit 1-1 summarizes the estimated costs for closing the Ghent impoundments. Explain why the estimated cost of clean closing of the gypsum stack ($71 million) is greater than the estimated cost of capping and closing the ash treatment basin #1 ($57 million) and is almost as much as the estimated cost of capping and closing the ash treatment basin #2 ($79.4 million).

A-17. The projected cost of closing a given surface impoundment is unlikely to be meaningfully comparable to the projected closure cost of another surface impoundment, even one at the same generating station. This is due to often large variations in a number of key variables concerning surface impoundments, including the impoundments' size and quantity of CCR materials already disposed of in the impoundments.

Also, the proposed closure plans are intended to comply with the CCR Rule in a lowest-cost reasonable manner on a station-by-station basis, not an impoundment-by-impoundment basis. Therefore, for example, KU might propose to incur added expense to clean-close an impoundment because beneficially using the CCR material from that impoundment to help cap and close another impoundment at the same station would produce net benefits relative to capping and closing both impoundments using other fill material.[1]

Concerning Ghent, Exhibit JNV-6, pages 2 through 4 of 50, provides the conceptual approach for closure of the Ghent CCR facilities. As described on page 3, the approach is to move the gypsum materials from the gypsum stack to use in the closure approach for ATB2. The estimated costs associated with the clean closing of the gypsum stack are primarily for the loading and hauling of material to ATB2. This results in a higher closure cost for the gypsum stack than simply capping and closing it, but that higher cost is more than offset by the savings resulting from beneficially using the CCR materials from the gypsum stack in closing ATB2. More particularly, the current plan for ATB2 is to beneficially use the CCR material from the gypsum stack clean closure to regrade the surface of ATB2 for storm water run-on and run-off control. The estimated costs for placement and compaction of the gypsum stack materials are currently shown with the cost of closing ATB2. Based on KU's current cost estimates and preliminary engineering, this

[1] *See, e.g.*, Voyles Testimony at 23 lines 17-21.

approach is the lowest-reasonable-cost means of closing all the surface impoundments at Ghent. KU is using the same station-by-station lowest-reasonable-cost approach at each affected generating station.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 18

Witness: John N. Voyles, Jr.

Q-18. Refer to the Voyles Testimony, Exhibit JNV-3, page 14. Explain the difference between the Total Initial Costs, the Lower ROM Range, and the Upper ROM Range, and is this response consistent for all of the Voyles' exhibits.

A-18. The CH2M studies are conceptual approaches for closure of the CCR impoundments. Conceptual estimates are Rough Order of Magnitude (ROM) estimates that are typically plus or minus 30% from the projected Total Initial Costs, as they are based on limited engineering. The Upper and Lower ROM are therefore general accuracy bounds of plus 30% (Upper ROM Range) and minus 30% (Lower ROM Range) around the projected Total Initial Costs. As explained in the footnote at the bottom of the table, these estimates are not for construction, but are for guidance in project evaluations based on the information available at the time of the study. All of the CH2M reports provided as exhibits are based on preliminary conceptual engineering, which is typically only 5-10% of the total engineering for a project.

The response above applies to all of the Voyles exhibits. The conceptual estimates are consistent with industry practice and standards and are reasonably reliable for supporting the Company's decisions and recommendations in its application.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 19

Witness: John N. Voyles, Jr.

Q-19. Refer to the Voyles Testimony, Exhibit JNV-3, page 15.

a. Explain the difference between the Cost 2015 Dollars and the Total.

b. Provide the technical memo referenced in footnote one.

c. Explain whether the response for part a. is consistent for all of the proposed project analysis in Exhibit JNV-3.

A-19. a. The Total column is an escalated cost estimate based on a 4% per annum escalation rate. The Total column used the Cost 2015 dollars, applied the annual percentage construction values shown and then escalated the estimate to the year in which the spending will occur.

b. The note is incorrect and should read, "2015 Costs are based on CH2M 'Coal Combustion Residual Pond Closure Evaluation: Green River Generating Station' technical memo dated September 18, 2015." The document cited in the corrected note is Exhibit JNV-3.

c. Yes, this is consistent for all proposed projects.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 20

Witness: R. Scott Straight

Q-20. Refer to the Direct Testimony of R. Scott Straight ("Straight Testimony"), page 7, regarding the mercury re-emission phenomenon. Provide a detailed description of the mercury re-emission phenomenon, including an explanation of the de-oxidization process, and discuss whether this phenomenon occurs at any other KU units that are equipped with wet flue-gas desulfurization technology.

A-20. During the coal combustion process, elemental mercury contained in the coal volatizes and becomes entrained in the flue gas stream. Depending on certain factors such as chloride content within the coal and oxidation conversion rates of Selective Catalytic Reduction (SCR) units, a certain percentage of the elemental mercury loses two electrons and oxidizes into its 2+ oxidation state. Oxidized mercury is much more soluble in water than elemental mercury. Ideally, the oxidized mercury is removed from the flue gas stream in the Wet Flue Gas Desulfurization (WFGD) unit wastewater. However, WFGD chemistry can create conditions where oxidized mercury is reduced back into its water-insoluble elemental state and thus re-emitted back into the flue gas stream.

Oxidation-Reduction Potential (ORP) is the measure of the affinity of WFGD slurry constituents to lose electrons (oxidation) or gain electrons (reduction). The higher the ORP, the more likely these reactions take place. At a high ORP, oxidized mercury regains two electrons and is reduced back into its elemental form. Controlling ORP is key in preventing this reaction.

In order to control ORP, each WFGD will receive an organo-sulfide additive injection system. The organo-sulfide technology mitigates mercury re-emission by lowering WFGD ORP to an optimized range. Each WFGD unit will require a specific dose of organo-sulfide dependent on Unit coal, WFGD design, WFGD chemistry, etc. These rates can only be determined through process optimization once the organo-sulfide injection systems are operational. Another function of the organo-sulfide additive is to bind to oxidized mercury in the WFGD slurry and force it into the WFGD solids. The mercury is then removed from the process through the gypsum. This will help reduce the amount of wastewater that will need to be treated.

With regard to whether this phenomenon occurs at any other KU units equipped with wet flue-gas desulfurization technology, Ghent Unit 3 tests conducted in 2012 show evidence of mercury re-emissions. Ghent Units 1 and 4 likely experience similar phenomenon given they combust the same coal and have the same vintage, same technology WFGDs; however KU has not specifically tested these units given their similarities to Ghent Unit 3.

Trimble County Unit 1 tests conducted in 2012 showed evidence of mercury re-emission and the addition of chemical additives effectively reduced the magnitude of events. The majority of testing showed increased mercury capture within the WFGD and an overall reduction of mercury emissions. Trimble County Unit 2 emissions testing conducted in 2013 indicates the Powder River Basin coal/bituminous coal blend that is combusted causes a halogen-limited environment that constrains mercury oxidation and decreases the effectiveness of any systems to capture oxidized or elemental mercury. Subsequent data has demonstrated the combination of powdered activated carbon injection and chemical additives to be effective in the reduction of mercury emissions.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 21

Witness: R. Scott Straight

Q-21. Refer to the Straight Testimony, page 8, regarding the injection of a halogenated chemical additive into the coal feeders on the Ghent units to provide a more effective process of reducing mercury emissions. Is the supplemental injection technology similar to the refined coal arrangement at the Ghent Generating Station that was approved by the Commission in Case No. 2015-00264?[2] If not, explain the difference between the two processes.

A-21. The refined coal technology and the supplemental injection technology are chemically similar but functionally different. Both the refined coal and the supplemental injection technologies utilize halogenated liquids designed to increase mercury oxidation. Oxidized mercury is more easily removed from the flue gas with the pulse jet fabric filter and wet flue gas desulfurization technologies, thus reducing overall mercury emissions. However, the technologies differ in implementation and final goals.

The refined coal facility applies two proprietary chemicals to the coal in very small, incremental amounts as the coal is loaded into the power plant bunkers. The goal for the refined coal arrangement is to produce refined coal as defined in Section 45 of the Internal Revenue Code. The refined coal must provide a reduction, measured in lab scale tests, of nitrogen oxide and mercury.

The supplemental injection technology adds a different halogenated liquid to the coal at the unit feeders in continuous, metered flow rates. The goal for the supplemental injection technology is to reduce stack mercury emissions to a level below MATS limits. Therefore, while the refined coal arrangement is intended to provide some cost effective mercury mitigation it cannot be relied upon for a MATS compliance strategy. In addition, the installation of the refined coal facilities is dependent on Clean Coal Solutions (the refined coal facility owner) finding a tax equity investor for the facility and the successful negotiation of a final arrangement. Any refined coal arrangement would also terminate when the Section 45 Production tax credit expires or when the facility no longer qualifies for the tax credits, currently projected to be in late 2021. Therefore, the supplemental injection technology is required for the timely and continuous long term compliance with MATS regulatory limits.

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[2] Case No. 2015-00264, Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance Into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling (Ky. PSC Nov. 24, 2015).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 22

Witness: Gary H. Revlett / Robert M. Conroy

Q-22. Refer to the Application, page 10, paragraph 22; the Direct Testimony of Gary H. Revlett ("Revlett Testimony"), at page 5, lines 18–22; and at page 20, line 5, through page 21, line 12.

a. Explain whether KU believes the closure of surface impoundments at the Green River, Tyrone, and Pineville stations will be recoverable through the environmental surcharge if compliance with Effluent Limitations Guidelines and Standards for the Steam Electric Power 8 Generating Point Source Category ("ELG") does not lead to their "mandatory closure under state law."

b. Provide any updates to the determination of whether the ELG will necessitate closure of these surface impoundments.

c. Explain whether KU believes the closure of these surface impoundments will be recoverable through the environmental surcharge, given that the stations are no longer actively engaged in the production of energy from coal.

A-22. a. Yes, the costs of closing surface impoundments at the Green River, Tyrone, and Pineville stations should be recoverable through the environmental surcharge even if compliance with ELG does not lead to mandatory closure under state law. KRS 278.183(1) states, in relevant part:

> [A] utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal . . . .

As set forth in Mr. Revlett's Direct Testimony (see pages 20-21), ELG could lead to mandatory closure under state law. In that event, environmental surcharge recovery is permitted. However, even if state law does not mandate the closure, state law may mandate some other form of remedial action. Faced with that, KU must pursue the most prudent and lowest-cost reasonable solution to comply with that remedial action - regardless of whether closure is specifically mandated. Further, *because* that solution will be pursued in order to "comply with environmental requirements" the costs of that solution are recoverable under KRS 278.183, just like KU's other CCR-disposal projects.

Given the developing status of the state's position on the issue of these types of surface impoundments, KU cannot be certain what sort of remedial actions the state may pursue (or even from which state agency a remedial action may come). However, the Kentucky Pollution Discharge Elimination System ("KPDES") permits KU had for each impoundment expired long ago. KU timely applied for the renewal of those permits to the Kentucky Division of Water ("KDOW") (which resulted in an administrative continuance of the original permits), but KDOW has not acted on those applications. When KDOW does, it is reasonable to expect the new permits will be more rigorous than the original permits.

Since Green River, Tyrone, and Pineville have ceased electrical generation and they have no equipment in use that is subject to the new more restrictive ELG standards, the water in the ash ponds are regulated in the ELG rule as "legacy" wastewater and can continue to be discharged under the old low volume wastewater ELG criteria. However, the new ELG requirements are indicative of the more restrictive state and federal wastewater discharge limits that are being imposed. It is likely the new permits from KDOW will require compliance with Kentucky's Surface Water Standards for metals such as mercury. If that happens, KU will have to comply with those discharge limitations or close the impoundments. This single example of what may occur from a state regulatory perspective means simply closing the impoundments is the most prudent course of action to: (1) minimize environmental risk; (2) avoid escalating costs for engineering, construction, and materials; (3) achieve economies of scale that will result by closing contemporaneously with the CCR-Rule required closures; and (4) address potential changes in state CCR law.

b. KU does not believe the ELG standards specifically require closure.

c. The fact that the Green River, Tyrone, and Pineville stations are no longer actively engaged in the production of energy from coal is irrelevant to the issue of whether closing costs can be recovered through the environmental surcharge. As Mr. Revlett explains in his testimony (see page 5), that fact is important as to whether the CCR Rule applies, but, pursuant to KRS 278.183, cost recovery is permissible for costs necessary to comply with requirements for coal combustion wastes and by-products – the exact type of material in these impoundments. Unlike the CCR Rule, KRS 278.183 does not make a distinction between active and inactive facilities. <u>*See also*</u> *In the Matter of: Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for Construction of an Ash Landfill at J.K. Smith Station, the Removal of Impounded Ash from William C. Dale Station for Transport to J.K. Smith and Approval of a Compliance Plan Amendment for Environmental Surcharge Recovery*, Case No. 2014-00252, Order at 13 (Mar. 6, 2015).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 23

Witness: Charles R. Schram / Robert M. Conroy

Q-23. Refer to the Direct Testimony of Charles R. Schram ("Schram Testimony"), page 5, lines 5–8, state, "If the Companies determine that complying with the CPP and ELG is more costly than retiring coal units and replacing the capacity, they can likely operate the units through 2021 without incurring any CPP and ELG compliance costs."

a. If this were to occur, confirm that coal units would be retired.

b. If the retirement in part a. above is confirmed, provide, by plant, the net book value at the time of retirement and the proposed method of recovery for any stranded costs.

A-23. a. The statement is confirmed. If the Companies determine complying with these regulations is more costly than retiring coal units and replacing the capacity, coal units would be retired and the units' capacity would be replaced.

b. See table below. Prudently incurred costs are recoverable through rates. The Companies have not determined the method of recovery they would propose concerning the recovery of any remaining book value of such retired assets. The Companies are aware the Commission has permitted the recovery of and on such amounts through the amortization of regulatory assets.[3]

Station	**Net Book Value* (December 2021, $M)**
Brown	791
Ghent	2,129
Trimble County (KU's Share)	835

*Net book value estimates exclude any ELG compliance costs and reflect current depreciation rates.

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[3] *See, e.g., In the Matter of: Application of East Kentucky Power Cooperative, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Undepreciated Balance of the William C. Dale Generating Station,* Case No. 2015-00302, Order (Feb. 11, 2016); *In the Matter of: Application of Kentucky Power Company for: (1) a General Adjustment of Its Rates for Electric Service; (2) an Order Approving Its 2014 Environmental Compliance Plan; (3) an Order Approving Its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief,* Case No. 2014-00396, Order (June 22, 2015).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 24

Witness: Charles R. Schram

Q-24. Refer to Schram Testimony, page 5, lines 20–22, state that, "As a result, the Companies evaluated these projects over the Companies' standard 30-year analysis period with high-level estimates for CPP and ELG compliance costs." Also, refer to Schram Testimony, page 6, lines 11–13, which state, "For this reason, the 30-year retirement analysis assumed no incremental cost for CPP compliance at Trimble County." Explain why any difference between the analyses included high-level estimates and another assumed no incremental cost.

A-24. The two statements are consistent. The Companies' analysis of the Trimble County projects considered high-level estimates for CPP compliance costs, and determined these cost estimates are likely zero. In a scenario where the Companies' Brown, Ghent, and Mill Creek coal units were retired and replaced with renewable or new natural gas-fired generation with CO_2 emissions ranging from 0 lb/MWh to approximately 1,000 lb/MWh, the Companies' generating portfolio – even if the Trimble County coal units operated at full capacity – would already comply with any reasonable interpretation of the CPP. Therefore, no additional cost for carbon emissions (above and beyond the cost to retire and replace the coal-fired capacity at Brown, Ghent, and Mill Creek) was included in the analysis of the Trimble County projects.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 25

Witness: Charles R. Schram

Q-25. Refer to Schram Testimony, page 8, lines 10–12, which state that "no other production costs or other investments subsequent to 2021 are considered in the evaluation." Explain why no other production costs or other investments subsequent to 2021 were considered.

A-25. To avoid speculation regarding ELG and CPP compliance costs and to demonstrate the proposed projects at Brown and Ghent are justified even if the units are retired as soon as the end of 2021, KU's analyses of the projects at Brown and Ghent evaluate alternatives based on the present value of revenue requirements ("PVRR") for costs incurred from 2016 through 2021. Revenue requirements for capital costs extend through the remaining book life of the generating unit, but revenue requirements for operating costs are generated only in the years the operating costs occur. To correctly assess the PVRR of capital costs incurred from 2016 through 2021, the PVRR calculation included all of the capital revenue requirements created by the capital costs incurred through the end of 2021, even though the recovery of such costs would ordinarily occur over a much longer time. This analytical approach ensures the capital investments KU proposes to make from 2016 through 2021 are economical even if they have no useful life beyond 2021. But it would be incorrect in such an analysis to include operating costs beyond 2021 or to include revenue requirements associated with capital investments made after 2021; such costs bear on whether it is economical to operate the units beyond 2021, not whether it is economical to make the capital investments KU proposes to make through 2021.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 26

Witness: Charles R. Schram / Robert M. Conroy

Q-26. Refer to Schram Testimony, page 15, lines 5–17. Provide any net book value of the alternatives that might be considered at the time of retirement and the proposed method of recovery for any stranded costs.

A-26. See table below. Prudently incurred costs are recoverable through rates. The Companies have not determined the method of recovery they would propose concerning the recovery of any remaining book value of such retired assets. The Companies are aware the Commission has permitted the recovery of such amounts through the amortization of regulatory assets.[4]

Alternative	**Assumed Brown Units 1-3 Retirement Date**	**Net Book Value on Retirement Date* (Brown Units 1-3, $M)**
Operate through 2021	December 2021	791
Retire in 2019: NGCC/SCCT	December 2018	838
Retire in 2019: SCCT	December 2018	838
Natural Gas Conversion	December 2021	945

*Net book value estimates exclude any ELG compliance costs and reflect current depreciation rates.

[4] *See, e.g., In the Matter of: Application of East Kentucky Power Cooperative, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Undepreciated Balance of the William C. Dale Generating Station,* Case No. 2015-00302, Order (Feb. 11, 2016); *In the Matter of: Application of Kentucky Power Company for: (1) a General Adjustment of Its Rates for Electric Service; (2) an Order Approving Its 2014 Environmental Compliance Plan; (3) an Order Approving Its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief,* Case No. 2014-00396, Order (June 22, 2015).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 27

Witness: Charles R. Schram

Q-27. Refer to the Schram Testimony, Exhibit CRS-1, page 4, Table 1. Explain why the CCR production increases by year from 2016 to 2021.

A-27. CCR production at the E.W. Brown Generating Station increases due to the forecast for increasingly favorable economics of coal-fired generation at the station. Over the six year analysis period, natural gas prices in the Mid gas price scenario increase from $3.17/mmBtu in 2016 to $4.72/mmBtu in 2021 (see Schram Testimony, Exhibit CRS-1, page 16, Table 11) while coal prices are projected to increase more slowly. The increasing natural gas prices result in relatively lower costs for Brown's coal generation.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 28

Witness: Charles R. Schram

Q-28. Refer to the Schram Testimony, Exhibit CRS-1, regarding the Analysis of 2016 ECR Projects E.W. Brown Generating Station – Generation Planning & Analysis January 2016. Provide all work papers in Excel spreadsheet format with all cell formulas intact and unprotected and all rows and columns fully accessible for all modeling performed in preparing the analyses set forth in Exhibit CRS-1.

A-28. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

Attachment
Confidential

The entire attachment is Confidential and provided separately under seal.

Please also see the Petition to Deviate.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 29

Witness: Charles R. Schram

Q-29. Refer to the Schram Testimony, Exhibit CRS-2, regarding the Analysis of 2016 ECR Projects Ghent Generating Station – Generation Planning & Analysis January 2016. Provide all work papers in Excel spreadsheet format with all cell formulas intact and unprotected and all rows and columns fully accessible for all modeling performed in preparing the analyses set forth in Exhibit CRS-2.

A-29. See the response to Question No. 28. Also see attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

Attachment
Confidential

The entire attachment is Confidential and provided separately under seal.

Please also see the Petition to Deviate.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 30

Witness: Charles R. Schram

Q-30. Refer to the Schram Testimony, Exhibit CRS-3, regarding the Analysis of 2016 ECR Projects Trimble County Generating Station – Generation Planning & Analysis January 2016. Provide all work papers in Excel spreadsheet format with all cell formulas intact and unprotected and all rows and columns fully accessible for all modeling performed in preparing the analyses set forth in Exhibit CRS-3.

A-30. See the response to Question Nos. 28 and 29. Also see attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

Attachment
Confidential

The entire attachment is Confidential and provided separately under seal.

Please also see the Petition to Deviate.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 31

Witness: Charles R. Schram

Q-31. Refer to the Schram Testimony, Exhibit CRS-1, Analysis of 2016 ECR Projects E.W. Brown Generating Station – Generation Planning & Analysis January 2016. Provide the Brown analysis using KU's standard 30-year analysis period.

A-31. As discussed in Mr. Schram's testimony and exhibits, much uncertainty exists regarding the costs to comply with the U.S. Environmental Protection Agency's ELG and CPP. The final version of the ELG was published only recently and specifies a compliance deadline of no later than December 2023. The Companies have developed high-level ELG compliance cost estimates, but more refined cost estimates will not be available for 12 to 18 months. The future of the CPP is particularly uncertain: on February 9, 2016, the U.S. Supreme Court issued an order staying the CPP pending all appellate review of the CPP, including any review by the Court.

Therefore, the Companies chose to evaluate projects 36 and 42 based on costs incurred and benefits produced through 2021 to simplify the analysis and eliminate the need to speculate about compliance costs related to ELG or any other environmental regulation that may impact coal-fired generation beyond 2021. The analysis shows the proposed projects are lowest-reasonable-cost even if the Brown coal units are retired at the end of 2021, which speaks to the value of the Brown coal units in an operating environment with no costs for carbon emissions.

Table A below compares the results of the analysis presented in Table 6 on page 11 of Exhibit CRS-1 to the results of an analysis of the same alternatives evaluated over a 30-year period. For each alternative in the 30-year analysis, two 368 MW NGCC units are assumed to be commissioned at the Brown station in 2022. As a result, the costs for each alternative beyond 2021 are the same and the differences in the present value of revenue requirements ("PVRR") in the 30-year analysis are the same as the PVRR differences in the short-term analysis. The 30-year analysis assumes no costs for carbon emissions throughout the analysis period. This assumption and all other assumptions that impact costs after 2021 have no bearing on the analysis since these assumptions are the same for all alternatives.

Table A – Brown Analysis Results ($M, 2016 Dollars)

		Short-Term Analysis		30-Year Analysis	
Gas Price	**Alternative**	**PVRR of Costs Incurred from 2016 to 2021**	**Diff from Best**	**PVRR (2016-2045)**	**Diff from Best**
Low	Operate through 2021	5,222	5	18,915	5
	Retire in 2019: NGCC /SCCT	5,276	58	18,968	58
	Retire in 2019: SCCT	5,217	0	18,910	0
	Natural Gas Conversion	5,306	88	18,998	88
Mid	Operate through 2021	5,320	0	20,416	0
	Retire in 2019: NGCC /SCCT	5,396	76	20,493	76
	Retire in 2019: SCCT	5,335	16	20,432	16
	Natural Gas Conversion	5,427	108	20,524	108
High	Operate through 2021	5,457	0	21,739	0
	Retire in 2019: NGCC /SCCT	5,576	119	21,858	119
	Retire in 2019: SCCT	5,514	57	21,796	57
	Natural Gas Conversion	5,610	153	21,893	153

Table B below contains a more detailed breakdown of results from the 30-year analysis. In addition to the alternatives considered in Table A, Table B includes a fifth alternative that assumes the Brown coal units operate through the end of the 30-year analysis period (“Continued Operation”). This alternative assumes the Companies’ future analysis of more detailed ELG compliance costs results in a recommendation to comply with ELG at Brown and continue operating the Brown coal units. In an operating environment with no costs for carbon emissions, this alternative is least-cost in all gas price scenarios. The impact of carbon and other regulations impacting coal-fired generation would have to increase the estimated cost of continuing to operate the Brown coal units by $124 million to $1.1 billion before a decision to retire the Brown coal units would be considered least-cost.

Table B – Brown Analysis Results ($M, 2016 Dollars)

Gas Price	Alternative	System Production Costs	Other Capital and FOM	ECR Project Costs	Replacement Capacity Costs	NG Conversion	Trans. System Upgrade	New NGCC Costs	Total	Diff from Best
Low	Operate through 2021	17,001	204	126	0	0	17	1,567	18,915	124
	Retire in 2019: NGCC/SCCT	16,981	114	34	216	0	57	1,567	18,968	178
	Retire in 2019: SCCT	17,018	114	34	120	0	57	1,567	18,910	120
	Natural Gas Conversion	17,007	201	34	0	172	17	1,567	18,998	208
	Continued Operation	17,141	986	126	0	0	17	520	18,790	0
Mid	Operate through 2021	18,502	204	126	0	0	17	1,567	20,416	617
	Retire in 2019: NGCC/SCCT	18,505	114	34	216	0	57	1,567	20,493	693
	Retire in 2019: SCCT	18,540	114	34	120	0	57	1,567	20,432	632
	Natural Gas Conversion	18,533	201	34	0	172	17	1,567	20,524	724
	Continued Operation	18,151	986	126	0	0	17	520	19,800	0
High	Operate through 2021	19,825	204	126	0	0	17	1,567	21,739	1,100
	Retire in 2019: NGCC/SCCT	19,871	114	34	216	0	57	1,567	21,858	1,219
	Retire in 2019: SCCT	19,904	114	34	120	0	57	1,567	21,796	1,156
	Natural Gas Conversion	19,902	201	34	0	172	17	1,567	21,893	1,253
	Continued Operation	18,990	986	126	0	0	17	520	20,639	0

In the absence of a more detailed ELG compliance cost estimate, the "Continued Operation" alternative utilized the high-level cost estimate included in Table 8 on page 13 of Exhibit CRS-1 ($143 million; see "2016 Plan with Updated ECR Costs").[5] The Companies do not incur ELG compliance costs in the first four alternatives because the Brown coal units are assumed to retire in 2022. When more refined ELG compliance cost estimates are available in 12 to 18 months, the Companies will assess these costs in light of the uncertainty that exists with carbon regulations and other regulations that may impact coal-fired generation in the future. Even if that analysis concludes retirement is the least-cost alternative, operating the Brown coal units through at least 2021 – as demonstrated in Table A – is the least-cost retirement alternative.

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

[5] A complete summary of capital and fixed O&M cost assumptions through 2045 is attached to this response along with other work papers.

Attachment Confidential

The entire attachment is Confidential and provided separately under seal.

Please also see the Petition to Deviate.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 32

Witness: Charles R. Schram

Q-32. Refer to the Schram Testimony, Exhibit CRS-2, Analysis of 2016 ECR Projects Ghent Generating Station – Generation Planning & Analysis January 2016. Provide the Ghent analysis using KU's standard 30-year analysis period.

A-32. As discussed in Mr. Schram's testimony and exhibits, much uncertainty exists regarding the costs to comply with the U.S. Environmental Protection Agency's Effluent Limitation Guidelines ("ELG") and Clean Power Plan ("CPP"). The final version of the ELG was published only recently and specifies a compliance deadline of no later than December 2023. The Companies have developed high-level ELG compliance cost estimates, but more refined cost estimates will not be available for 12 to 18 months. The future of the CPP is particularly uncertain: on February 9, 2016, the U.S. Supreme Court issued an order staying the CPP pending all appellate review of the CPP, including any review by the Court.

Therefore, the Companies chose to evaluate projects 37, 38, and 40 based on costs incurred and benefits produced through 2021 to simplify the analysis and eliminate the need to speculate about compliance costs related to ELG or any other environmental regulation that may impact coal-fired generation beyond 2021. The analysis shows the proposed projects are lowest-reasonable-cost even if the Ghent coal units are retired at the end of 2021, which speaks to the value of the Ghent coal units in an operating environment with no costs for carbon emissions.

Table A below compares the results of the analysis presented in Table 11 on page 13 of Exhibit CRS-2 to the results of an analysis of the same alternatives evaluated over a 30-year period. For each alternative in the 30-year analysis, five 368 MW NGCC units are assumed to be commissioned at the Ghent station in 2022. As a result, the costs for each alternative beyond 2021 are the same and the differences in the present value of revenue requirements ("PVRR") in the 30-year analysis are the same as the PVRR differences in the short-term analysis. The 30-year analysis assumes no costs for carbon emissions throughout the analysis period. This assumption and all other assumptions that impact costs after 2021 have no bearing on the analysis since these assumptions are the same for all alternatives.

Table A – Ghent Analysis Results ($M, 2016 Dollars)

		Short-Term Analysis		**30-Year Analysis**	
Gas Price	**Alternative**	**PVRR of Costs Incurred from 2016 to 2021**	**Diff from Best**	**PVRR (2016-2045)**	**Diff from Best**
Low	Retire in 2019	6,082	278	21,828	278
	Operate through 2021	5,805	0	21,551	0
Mid	Retire in 2019	6,303	400	25,030	400
	Operate through 2021	5,903	0	24,630	0
High	Retire in 2019	6,614	574	27,852	574
	Operate through 2021	6,040	0	27,278	0

Table B below contains a more detailed breakdown of results from the 30-year analysis. In addition to the alternatives considered in Table A, Table B includes a third alternative that assumes the Ghent units operate through the end of the 30-year analysis period ("Continued Operation"). This alternative implicitly assumes the Companies' future analysis of more detailed ELG compliance costs results in a recommendation to comply with ELG at Ghent and continue operating the Ghent units. In an operating environment, with no costs for carbon emissions, this alternative is least-cost in all gas price scenarios. The impact of carbon and other regulations impacting coal-fired generation would have to increase the estimated cost of continuing to operate the Ghent coal units by $1.1 billion to more than $5.0 billion before a decision to retire the Ghent units would be considered least-cost.

Table B – Ghent Analysis Results ($M, 2016 Dollars)

Gas Price	**Alternative**	**System Production Costs**	**Other Capital and FOM**	**ECR Project Costs**	**Replacement Capacity Costs**	**New NGCC Costs**	**Total**	**Diff from Best**
Low	Retire in 2019	17,144	271	268	683	3,463	21,828	1,405
	Operate through 2021	17,143	523	422	0	3,463	21,551	1,127
	Continued Operation	17,141	2,340	422	0	520	20,424	0
Mid	Retire in 2019	20,345	271	268	683	3,463	25,030	3,597
	Operate through 2021	20,222	523	422	0	3,463	24,630	3,197
	Continued Operation	18,151	2,340	422	0	520	21,433	0
High	Retire in 2019	23,167	271	268	683	3,463	27,852	5,579
	Operate through 2021	22,870	523	422	0	3,463	27,278	5,005
	Continued Operation	18,990	2,340	422	0	520	22,273	0

In the absence of a more detailed ELG compliance cost estimate, the "Continued Operation" alternative utilized the high-level cost estimate included in Table 12 on page 14 of Exhibit CRS-2 ($155 million; see "2016 Plan with Updated ECR Costs").[6] The Companies do not incur ELG compliance costs in the first two alternatives because the Ghent units are assumed to retire in 2022. When more refined ELG compliance cost estimates are available in 12 to 18 months, the Companies will assess these costs in light of the uncertainty that exists with carbon regulations and other regulations that may impact coal-fired generation in the future. Even if that analysis concludes retirement is the least-cost alternative, operating the Ghent units through at least 2021 – as demonstrated in Table A – is the least-cost retirement alternative.

See the response to Question No. 31 for attachments.

[6] A complete summary of capital and fixed O&M cost assumptions through 2045 is attached to this response along with other work papers.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 33

Witness: John J. Spanos / John N. Voyles Jr.

Q-33. The Direct Testimony of John J. Spanos, page 4, lines 5–7, states, "Based on the engineering study, the costs of removal for the Ghent Unit 4 ash pond are $217,401,690. Therefore, the full recovery of the Ghent Unit 4 ash ponds over their remaining life is $236,760,375."

a. Cite and provide the engineering study.

b. Provide the kinds of and amounts of the costs of removal for the Ghent Unit 4 ash ponds.

A-33. a. The engineering study referenced is Exhibit JNV-6. Also see the attached document provided to me from the Company, which summarizes the costs of removal for the Ghent Unit 4 (Ash Treatment Basin No. 2) ash pond based on engineering studies performed by or for the Company.

b. The document provided in part (a) of this response sets forth the location and type of cost of removal projects for each location including Ghent. See attached for the underlying asset values for the impoundment facilities provided by the Company.

KU and LG&E 2016 ECR Plan (01/06/2016)

ECR Project	Plant	Facility	Total ($M)	2015	2016	2017	2018	2019	2020	2021	2022	2023
KU 39	Green River	CCR - Main Ash Pond Capping	$20.2	$0.5	$1.1	$8.0	$10.6	$0	$0	$0	$0	$0
KU 39	Green River	CCR - ATB #2 Capping	$21.4	$0.6	$1.1	$8.9	$10.9	$0	$0	$0	$0	$0
KU 39	Green River	CCR - SO2 Pond	$15.2	$0.2	$0.7	$5.2	$9.1	$0	$0	$0	$0	$0
KU 39	Pineville	CCR - Ash Pond Capping	$8.0	$0	$0.3	$0.2	$2.7	$4.8	$0	$0	$0	$0
KU 39	Tyrone	CCR - Ash Pond Capping	$13.1	$0	$0.9	$0.4	$7.3	$4.5	$0	$0	$0	$0
KU 40	Ghent	CCR - ATB #1 Capping	$69.5	$1.0	$3.3	$4.0	$1.3	$6.2	$5.4	$25.9	$22.3	$0
KU 40	Ghent	CCR - ATB #2 Capping	$92.9	$0	$6.7	$10.3	$9.8	$7.0	$21.5	$26.5	$11.1	$0
KU 40	Ghent	CCR - Gypsum Stack	$78.7	$0	$8.3	$20.7	$16.2	$23.7	$9.9	$0	$0	$0
KU 40	Ghent	CCR - Secondary Pond Cleanout	$3.4	$0	$0.4	$0.3	$0.6	$2.1	$0	$0	$0	$0
KU 40	Ghent	CCR - Reclaim Pond Cleanout	$5.4	$0	$0.5	$0.5	$0.3	$2.8	$0.6	$0.6	$0	$0
KU 41	Trimble County	CCR - Ash Pond Capping (net, KU 48%)	$48.8	$0.8	$0.5	$1.1	$3.3	$3.7	$9.6	$7.4	$11.9	$10.6
KU 41	Trimble County	CCR - Gypsum Pond Capping (net, KU 48%)	$13.9	$0	$0.5	$0.7	$1.4	$7.9	$3.5	$0	$0	$0
KU 42	E.W. Brown	CCR - Aux Pond Capping	$32.7	$0	$0.5	$0.7	$0.5	$3.8	$3.4	$3.6	$9.9	$10.2
LGE 29	Mill Creek	CCR - Ash Pond Capping	$51.0	$1.6	$7.1	$0.5	$0.1	$14.3	$27.4	$0	$0	$0
LGE 29	Mill Creek	CCR - Clearwell Pond Cleanout	$5.4	$0.0	$0.6	$4.7	$0.0	$0.0	$0.0	$0	$0	$0
LGE 29	Mill Creek	CCR - Construction Pond Cleanout	$7.3	$0.0	$0.5	$0.3	$6.5	$0.0	$0.0	$0	$0	$0
LGE 29	Mill Creek	CCR - Dead Storage Pond Cleanout	$6.4	$0.0	$0.7	$5.7	$0.0	$0.0	$0.0	$0	$0	$0
LGE 29	Mill Creek	CCR - Emergency Pond Cleanout	$5.5	$0.0	$0.5	$0.3	$4.7	$0.0	$0.0	$0	$0	$0
LGE 30	Trimble County	CCR - Ash Pond Capping (net, LG&E 52%)	$52.9	$0.9	$0.5	$1.1	$3.6	$4.0	$10.4	$8.0	$12.9	$11.5
LGE 30	Trimble County	CCR - Gypsum Pond Capping (net, LG&E 52%)	$15.0	$0	$0.5	$0.7	$1.5	$8.5	$3.8	$0	$0	$0
Total Spend ($M)			$566.7	$5.6	$35.3	$74.2	$90.5	$93.3	$95.6	$72.0	$68.1	$32.3
KU 2016 ECR Project Spend ($M)			$423.2	$3.1	$24.8	$60.9	$74.1	$66.4	$53.9	$64.0	$55.2	$20.8
LG&E 2016 ECR Project Spend ($M)			$143.5	$2.5	$10.5	$13.3	$16.4	$26.8	$41.6	$8.0	$12.9	$11.5

KU	Green River	$56.8
KU	Pineville	$8.0
KU	Tyrone	$13.1
KU	Ghent	$249.9
KU	Trimble County (net)	$62.7
KU	Brown	$32.7
Total ($M)		$423.2

LG&E	Mill Creek	$75.6
LG&E	Trimble County (net)	$67.9
Total ($M)		$143.5

Kentucky Utilities Company
Ponds Proposed for ECR Filing
as of November 2015

	Location	Plant Acct	Year	Cost	Asset ID	Depr Database Loc #
Ghent Ash Pond - ATB#1 Capping	Ghent Unit 1	131200	1974	$1,777,792.39	13678073	5651
Ghent Ash Treatment Basin #2	Ghent Unit 4	131200	1994	16,544,368.66	93594118	5654
	Ghent Unit 4	131200	2004	16,148,295.19	10771518	5654
Ghent Gypsum Stack	Ghent Unit 2 FGD	131200	1994	1,901,133.18	17147798	5658
Ghent Ash Pond - Secondary Pond	Ghent Unit 1	131100	1987	322,828.55	13677771	5651
Ghent Environmemtal Ponds - Reclaim Pond	Ghennt Unit 1 FGD	131100	1997	39,480.55	10632228	5650
Green River Ash Treatment Basin #1						
Green River Ash Treatment Basin #2						
Green River SO2 Pond						
	Green River Unit 3	131200	1978	1,831,840.98	10632821	5613
BR Auxiliary Pond - Aux Pond	Brown Unit 1	131200	1995	13,208,176.67	93594073	5621
	Brown Unit 3	131200	2008	19,802,080.26	70577100	5623
Pineville Ash Treatment Basin	Pineville Unit 3	131200	1977	91,265.89	10633623	5643
(Jointly Owned - See LG&E assets below)						
TC Ash Pond-KU - Ash Pond	Trimble County Unit 2	131100	1990	4,562,600.30	31167995	0321
TC Environmental Ponds-KU - Gypsum Pond	Trimble County Unit 2	131200	2011	4,610,665.23	103399148	0321
Tyrone Ash Treatment Basin	Tyrone Unit 3	131200	1977	575,455.72	93594028	5603
Total KU				$81,415,983.57		

Louisville Gas & Electric Company
Ponds Proposed for ECR Filing
as of November 2015

	Location	Plant Acct	Year	Cost		
Mill Creek Ash Pond	Mill Creek Unit 1	131100	1972	$411,750.29	10093145	0211
Mill Creek Clearwell Pond						
Mill Creek Construction Runoff Pond						
Mill Creek Dead Storage Pond						
Mill Creek Emergency Pond						
	Mill Creek Unit 3	131100	1980	1,263,768.52	10092880	0231
(Jointly Owned - See KU assets above)						
TC Ash Pond -LGE - Ash Pond	Trimble County Unit 1	131100	1990	4,942,817.00	14024169	0321
TC Environmental Ponds -LGE- Gypsum Pond	Trimble County Unit 2	131200	2011	5,057,242.50	103405851	0321
Total LG&E				$11,675,578.31		
Total				$93,091,561.88		

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00026

Question No. 34

Witness: Christopher M. Garrett / R. Scott Straight

Q-34. The Direct Testimony of Christopher M Garrett, page 11, lines 6–7, state, "[T]he O&M expenses associated with use of organo-sulfide and halogenated liquid chemicals are not included in base rates." Provide the annual costs of the organo-sulfide and halogenated liquid chemicals.

A-34. The projected annual costs of powdered activated carbon at the Ghent Station are $7-8 million. Based on test results at Trimble County 1, the annual costs of the organo-sulfide and halogenated liquid chemicals would be $3-4 million. Given current pricing provided in response to Question No. 3, the cost for these additives are projected to be offset by the savings from the reduction in powdered activated carbon costs approved in the 2011 ECR Plan Projects 34 and 35.