a PPL company

RECEIVED

SEP 15 2011

PUBLIC SERVICE COMMISSION

Jeff DeRouen, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Director - Rates
T 502-627-3324
F 502-627-3213
robert.conroy@lge-ku.com

September 14, 2011

RE: ***The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge***
Case No. 2011-00161

Dear Mr. DeRouen:

Enclosed please find an original and fifteen (15) copies of Kentucky Utilities Company's (KU) supplemental response to Question No. 20(b) of the Commission Staff's First Information Request dated July 12, 2011, in the above-referenced matter.

Also enclosed are an original and fifteen (15) copies of a Petition for Confidential Protection regarding certain information contained in response to Question No. 20(b).

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Robert M. Conroy

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

SEP 15 2011

PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00161

KENTUCKY UTILITIES COMPANY

SUPPLEMENTAL RESPONSE TO THE COMMISSION STAFF'S FIRST INFORMATION REQUEST

DATED JULY 12, 2011

FILED: SEPTEMBER 14, 2011

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 14th day of September 2011.

Notary Public (SEAL)

My Commission Expires:

July 21, 2015

KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request Dated July 12, 2011

Supplemental Response filed September 14, 2011

Case No. 2011-00161

Question No. 20

Witness: Charles R. Schram

Q-20. Refer to Schram Testimony at pages 3-4. The testimony references two related analyses which were performed by KU's Project Engineering department, along with Black & Veatch.

a. Provide the reports and all supporting workpapers for the suite of environmental compliance facilities for each coal unit in the generation fleet to determine whether all of the proposed facilities would be necessary to meet the applicable environmental regulations.

b. Provide the reports and all supporting workpapers for the determination for each generating unit if it would be more cost effective to install the facilities or to retire the unit and buy replacement power or generation.

c. If not included in parts a. and b. above, explain how the analyses considered the purchase of power (renewable or otherwise) and provide the workpapers and assumptions for each specific power purchase scenario.

d. As the costs of environmental compliance are realized, the relative price of smaller decentralized power generation becomes more attractive. Other utilities and companies in Kentucky are exploring the development of potential sources of generation including landfill methane, bio-digesters, biomass, and small natural gas wellheads. Explain whether the analyses considered the development of these or other potential distributed generation sources and provide the workpapers and assumptions for each scenario.

e. As the costs of environmental compliance are realized, the relative price of Demand Side Management and energy efficiency programs becomes more attractive. If not included in parts a. and b. above, explain whether and how the development of new and the expansion of existing programs is considered in the analyses.

A-20. **Original Response:**

a. The report and documentation is included in Exhibit JNV-2.

b. Exhibit CRS-1 contains the material supporting the determination for building controls or retiring the unit and constructing replacement generation.

c. The analyses do not consider power purchases, renewable or otherwise. Ultimately, market availability of suitable replacement capacity and energy is determined through the RFP process when replacing generation.

d. The Companies' 2011 Integrated Resource Plan evaluated multiple technologies, including renewable technologies, in the supply side screening process. The Companies have not seen information which supports the cost-effectiveness of decentralized power generation at the scale required to replace the generation assumed to be retired in the 2011 Compliance filing. Replacement generation for the units recommended for retirement will need to be dispatchable to meet the customers' energy needs and be of sufficient scale to replace the retired units' capacity. The RFP for new capacity and energy issued in December 2010 resulted in multiple responses from parties marketing renewable generation resources. The Companies have, and continue to, explore these options as well.

e. The analyses include the impact of programs in the 2011 DSM filing, but do not consider further energy efficiency programs. The need for replacement generation due to retirements of units assumed in the 2011 Compliance plan is unlike any plan to use incrementally increasing energy efficiency programs to meet incremental growth in load requirements. The scale of the retirements and their timing, all by the end of 2015, create an immediate need for capacity and energy at that time.

Supplemental Response:

a. [No change or supplement.]

b. Please see the attached Supplemental Analysis to the 2011 Air Compliance Plan contained in Exhibit CRS-1. The Supplemental Analysis was performed based on the updated fuel cost information (provided in response to KPSC-2 Question No. 32) contained in the resource assessment analysis for the Companies' Certificate of Public Convenience and Necessity ("CPCN") filing and revised cost estimates for controls at Cane Run. In the development of the CPCN filing, the Companies updated the analysis for building controls or retiring generating capacity. The Companies' determinations for building controls or retiring capacity as filed in the 2011 Compliance Plan did not change as a result of the attached update.

c. [No change or supplement.]

d. [No change or supplement.]

e. [No change or supplement.]

2011 Air Compliance Plan Supplemental Analyses

PPL companies

Generation Planning & Analysis
September 2011

Table of Contents

1 Cane Run Cost of Controls

In the 2011 Compliance Plan, new environmental controls were not recommended for the Cane Run, Green River, and Tyrone coal units. Table 1 contains the results of the Compliance Plan analysis for these units as well as the total capital cost of controls needed to comply with EPA regulations.[1]

Table 1 – NPVRR Differences and Capital Costs for Controls

	NPVRR ($Millions)			Capital ($Millions)
Unit(s)	**Install Controls (A)**	**Retire/Replace Capacity (B)**	**Difference (B)-(A)**	**Total Capital Cost of Controls – 2011 Compliance Plan**
Tyrone 3	33,125	33,124	(1)	45
Green River 3	33,124	33,055	(69)	45
Green River 4	32,917	32,823	(94)	66
Cane Run 4	33,055	32,967	(88)	295
Cane Run 5	32,975	32,917	(58)	399
Cane Run 6	32,967	32,975	8	310

The analyses of controls for Cane Run and Green River were based on initial cost estimates from Black and Veatch.[2] Because Tyrone 3 and Green River 3 are similar in size and vintage, the cost of controls for Tyrone 3 and Green River 3 was assumed to be equal. Given the operating characteristics, age, and size of the units as well as the controls needed to comply with current environmental regulations, the cost of controls at Green River and Tyrone cannot be justified.

Since a significant reduction in the cost of controls for Cane Run could impact the Companies' ultimate decision regarding Cane Run, the Companies developed a revised estimate for the cost of controls at Cane Run based on the recently constructed common WFGD system which serves three coal-fired units at Brown and the more detailed 2011 Black & Veatch studies for Ghent, Mill Creek, and Brown. The revised estimate for controls at Cane Run included a common WFGD system and common limestone processing facilities. In addition, the costs of baghouses were escalated by 37%.[3] The original and revised estimates for the cost of controls at Cane Run are summarized in Table 2.

---

[1] Updated results for the Green River and Tyrone coal units were provided in response to the supplemental requests for information of Rick Clewett, Raymond Barry, Sierra Club and the Natural Resource Defense Council dated August 18, 2011, Question No. 8.

[2] For the units for which controls are recommended, the cost estimates for controls were based on more refined engineering estimates from Black and Veatch included in the Compliance Plan.

[3] Compared to the initial round of cost estimates, the costs of baghouses in the more detailed estimates from Black & Veatch (in the Compliance filing for Ghent, Mill Creek, and Brown) were 37% higher on average.

Table 2 – Total Capital Cost of Cane Run Controls ($M)

Unit	Original Estimate: 2011 Compliance Plan	Revised Estimate[4]
Cane Run 4	295	133
Cane Run 5	310	144
Cane Run 6	399	180
Common	N/A	532
Total	1,004	990

Compared to the original estimate, the cost of controls in the revised estimate is $14 million lower. This reduction in capital cost equates to approximately $14 million reduction in PVRR. With the original cost estimates, the total PVRR for all of the Cane Run units is $138 million (in favor of retirement – see Table 1). Clearly, the PVRR reduction associated with the lower capital cost does not offset this total.[5]

[4] Values do not sum precisely to the total due to rounding.

[5] The common WFGD and limestone processing facilities in the revised estimate preclude the retirement of individual units at Cane Run.

2 Analysis of Key Drivers of the 2011 Compliance Plan

The analysis of the 2011 Compliance Plan was based on multiple inputs having a range of potential values. Because the Companies' need for capacity in 2016 is based in large part on the conclusions drawn from the Compliance Plan analysis, the Companies conducted various analyses to assess the reasonableness of the results. The following analyses are summarized in the sections below.

1. Fuel Price: The decisions to install new environmental controls were evaluated under various coal and natural gas price scenarios.
2. Future Operation: For each of the units for which controls are recommended, the Companies computed the number of years the units would have to continue to operate to justify the cost of the proposed controls.
3. Future Environmental Costs: For each of the units for which controls are recommended, the Companies computed the cost of potential future controls that could be incurred without changing the Companies' recommendation.
4. Ongoing Capital and Fixed O&M Costs: For each of the units for which controls are recommended, the Companies computed the increase in ongoing capital and fixed O&M that would reduce the difference in PVRR between installing controls and retirement to zero.

Based on the results of these analyses, the Companies' proposed projects in the 2011 Compliance Plan are unchanged.

2.1 Fuel Price

In the 2011 Compliance Plan analysis, the Companies – for each of the units for which a need for controls had been established – compared the difference in PVRR between (a) installing controls and (b) retiring the unit and replacing the capacity. These analyses are based on forecasts of coal and natural gas prices. If coal becomes relatively more expensive compared to gas, the options to install controls are less favored and retirement is more favored.

Table 3 summarizes the high sulfur coal and natural gas prices used in the 2011 Compliance Plan. The coal prices in Table 3 are a blend of short-term prices based on market quotes and a long-term price forecast developed by Wood Mackenzie, an energy and mining research and consulting firm. Beyond the fourth forecast year, coal prices are based entirely on the Wood Mackenzie forecast. The natural gas forecast is also a blended forecast. The first three years of the forecast are based on market quotes. Gas prices beyond the third year were developed by the PIRA Energy Group ("PIRA"), an energy consulting firm. The Compliance Plan prices were developed in 2010 and also used in the development of the Companies' 2011 IRP.

Table 3 – Coal and Natural Gas Prices ($/mmBtu)[6]

	2011 Compliance Plan	
Year	High Sulfur Coal	Natural Gas
2011	[redacted]	[redacted]
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		

Among the units for which controls are recommended in the 2011 Compliance Plan, the difference in PVRR between installing controls and retirement is smallest for Brown 1-2 ($228 million in favor of installing controls). The average margin between coal and natural gas prices in the 2011 Compliance Plan would have to decrease by 42% (from $5.73/mmBtu to $3.33/mmBtu) to reduce the PVRR difference for Brown 1-2 to zero, thus representing a neutral decision with respect to the installation of controls as compared to retirement.

Table 4 on the following page contains four sets of more recently developed price forecasts. Each set of forecasts was developed in 2011.[7] The column titled "2011 Wood Mac/PIRA" contains price forecasts that are updated versions of the forecasts used in the 2011 Compliance Plan; the longer-term coal portion of the coal forecast was developed by Wood Mackenzie and the longer-term portion of the gas price forecast was developed by PIRA. Wood Mackenzie and PIRA, respectively, also produce natural gas and coal price forecasts. The column titled "2011 Wood Mac" contains forecasts that reflect Wood Mackenzie's outlook for coal and natural gas prices; the column titled "2011 PIRA" contains forecasts that reflect PIRA's outlook for coal and natural gas prices.

[6] Concerning the information redacted from Tables 3 and 4 and Figure 1, please see the KU's response to Commission Staff's Second Information Request dated August 18, 2011, Question Nos. 32(c) and 32(e) and LG&E's response to Commission Staff's Second Information Request dated August 18, 2011, Question Nos. 23(c) and 23(e). The Companies obtained the redacted information from CERA and PIRA under subscription services. The Companies requested from CERA and PIRA authorization to disclose the redacted information, but neither CERA nor PIRA consented to the request.

[7] The most recent fuel forecasts the Companies previously produced were provided in response to Commission Staff Data Request Nos. 2-32 (KU) and 2-23 (LG&E).

Table 4 – Alternative Coal and Natural Gas Prices ($/mmBtu)

	2011 Wood Mac/PIRA		2011 PIRA		2011 Wood Mac		2011 CERA	
Year	High Sulfur Coal	Natural Gas	High Sulfur Coal	Natural Gas	High Sulfur Coal	Natural Gas	High Sulfur Coal	Natural Gas
2012	[redacted]							
2013	[redacted]							
2014	[redacted]							
2015	[redacted]							
2016	[redacted]							
2017	[redacted]							
2018	[redacted]							
2019	[redacted]							
2020	[redacted]							
2021	[redacted]							
2022	[redacted]							
2023	[redacted]							
2024	[redacted]							
2025	[redacted]							

The differences between the 2011 Wood Mac coal forecast and the 2011 Wood Mac/PIRA coal forecast are explained by the fact that the Companies' contracted position is not factored into the shorter-term portion of the 2011 Wood Mac coal forecast. Likewise, the differences between the 2011 PIRA gas forecast and the 2011 Wood Mac/PIRA gas prices are explained by the fact that the market forward gas prices are not factored into the shorter-term portion of the 2011 PIRA gas forecast. The 2011 CERA price forecasts were developed by IHS CERA ("CERA").

The coal forecasts from Wood Mackenzie and PIRA are comparable. As a result, the relationships between coal and natural gas prices in the 2011 Wood Mac/PIRA and 2011 PIRA forecasts are consistent. Compared to the 2011 Compliance Plan prices, the average margin between coal and natural gas prices in these forecasts narrowed by approximately 15% (from $5.90/mmBtu to $5.00/mmBtu). This margin is 28% lower in the 2011 Wood Mac forecasts and 47% lower in the 2011 CERA forecasts (compared to the 2011 Compliance Plan prices). The 2011 CERA coal prices are consistent with the 2011 Wood Mackenzie and PIRA coal prices. However, the Wood Mackenzie and CERA gas forecasts are lower than the PIRA gas forecast.

The Companies evaluated the decisions to install controls under the 2011 Wood Mac/PIRA forecasts, the 2011 Wood Mac forecasts, and the 2011 CERA forecasts.[8] The differences in PVRR between (a) installing controls and (b) retiring and replacing capacity are summarized in Table 5 for each case. The Base Case values are taken from the 2011 Compliance Plan.[9]

---

[8] Because the relationships between gas and coal prices in the 2011 PIRA forecasts and the 2011 Wood Mac/PIRA forecasts are consistent, the Companies did not evaluate the decisions to install controls using the 2011 PIRA forecasts.

[9] The results for the Green River and Tyrone coal units were updated in response to the supplemental requests for information (Question No. 8) of Rick Clewett, Raymond Barry, Sierra Club and the Natural Resource Defense Council.

Table 5 - PVRR of Installing Controls vs. Retiring and Replacing Capacity ($M, $2011)

Unit(s)	Base Case	2011 Wood Mac/PIRA	2011 Wood Mac	2011 CERA
Tyrone 3	(1)	(7)	(10)	(17)
Green River 3	(69)	(62)	(88)	(98)
Brown 3	601	495	357	268
Cane Run 4	(88)	(141)	(187)	(239)
Cane Run 6	8	(55)	(145)	(152)
Brown 1-2	228	153	39	(27)
Cane Run 5	(58)	(103)	(171)	(201)
Ghent 3	914	746	520	399
Ghent 1	794	657	400	272
Green River 4	(94)	(105)	(140)	(150)
Mill Creek 4	859	718	481	339
Trimble County 1	993	901	675	556
Ghent 4	1,155	999	750	600
Mill Creek 3	756	674	453	338
Ghent 2	1,139	995	755	606
Mill Creek 1-2	1,022	845	536	338

A positive value in Table 5 demonstrates that the cost of retiring and replacing capacity is more expensive than installing controls. The Companies' recommendations to install controls (at Brown, Ghent, Mill Creek, and Trimble County) are unchanged in the 2011 Wood Mac/PIRA case and the 2011 Wood Mac case. While not changing the Companies' recommendation, in the 2011 CERA case, retiring and replacing the capacity at Brown 1-2 is less costly than installing controls.

Figure 1 plots the natural gas and coal price forecasts in Table 4 as well as price forecasts from other sources. Compared to the coal price forecasts in Figure 1, the outlook for natural gas prices is more uncertain. The 'HH – Threshold' forecast is the forecast of natural gas prices that – in combination with the 2011 Compliance Plan coal price forecast – reduces the PVRR difference for Brown 1-2 to zero, thus representing a neutral decision with respect to the installation of controls as compared to retirement. As seen in Figure 1, only the CERA natural gas forecast falls slightly below this threshold beginning in 2019.

Figure 1 – Comparison of HH Natural Gas and ILB HS Coal Price Forecasts

[redacted]

2.2 Future Operation

Because the development and impact of potential future environmental regulations is uncertain, the Companies computed the number of years the units for which controls are recommended would have to continue to operate to justify the cost of controls. For each unit, this number of years was computed using an iterative process. In each iteration, the PVRR of the 'retire and replace capacity' case was compared to the PVRR of a modified version of the 'install controls' case that assumed that the unit with controls would be retired several years after controls were initially added. In the iterative process, the retirement year for the units with controls was increased until the difference in PVRR between the cases was close to zero, thus representing a neutral decision with respect to the installation of controls as compared to retirement. Table 6 summarizes the results of this analysis as well as the projected end of each unit's economic life based on a 2007 life assessment study.[10] For each of the units for which controls are recommended, the year through which the unit would have to operate to justify the cost of controls is earlier than the projected end of the unit's economic life.

[10] The 2007 Life Assessment Study was provided in response to Commission Staff's First Information Request dated July 12, 2011, Question No. 32(i). The projected end of the economic life of each unit is uncertain. Ultimately, the actual life of a unit is based on the way the unit is operated and maintained. The Companies believe that continuing a prudent level of ongoing maintenance and investment at its remaining generating units will ensure the ongoing reliable operation of the units and minimize the potential for a significant mechanical failure. Trimble County 1, Mill Creek 3-4, and Ghent 3-4 are being maintained to ensure that, year over year, a minimum 30-year remaining useful life is expected. Mill Creek 1-2, Brown 1-3, and Ghent 1-2 are being maintained to ensure that, year over year, a minimum 20-year remaining useful life is expected. Clearly, the number of years each of the units would have to operate to justify the cost of controls is less than that unit's life expectancy based on the way the units are being maintained.

Table 6 – Year through which Unit Would Have to Operate to Justify Cost of Controls

Unit	Year through which Unit Would Have to Operate to Justify Cost of Controls	Projected End of Economic Life Based on 2007 Life Assessment Study
Ghent 2	2018	2027
Ghent 4	2018	2044
Trimble County 1	2018	2050
Brown 3	2019	2026
Ghent 3	2020	2041
Brown 1-2	2021	2026
Ghent 1	2021	2026
Mill Creek 3	2021	2038
Mill Creek 4	2023	2042
Mill Creek 1-2	2024	2026

The Companies believe that stricter limits on the emission of CO_2 could have major impacts on the entire utility industry, LG&E/KU, and its customers. Potential CO_2 regulations could take many forms. It is currently unclear if, or when, commercially viable and scalable CO_2 control technologies will become available, the addition of which could impose additional costs on fossil-fueled generation fleets.

2.3 Future Environmental Costs

The 2011 Compliance Plan analysis considered estimates for potential future environmental costs related to cooling water intake structures (section 316(b) of the Clean Water Act) and wastewater discharge compliance; all of which will require capital investment within the next 10-15 years.[11] The Compliance Plan does not recommend (and therefore did not consider the cost of) SCRs for Brown 1-2, Ghent 2, or Mill Creek 1-2. Because more stringent NO_x emission reduction requirements in the future could require the construction of SCRs on some or all of these units, the Companies considered the cost of potential future controls and whether these costs could be incurred without changing the Companies' current recommendation. For these units, Table 7 summarizes the differences in PVRR between (a) installing controls and (b) retiring and replacing capacity as well as capital cost estimates and revenue requirements associated with new SCRs. The SCR capital costs and PVRR values are taken from the 2011 Compliance Plan analysis.

Table 7 – Difference in PVRR and Estimates of SCR Capital Costs ($M, $2011)

Unit	Base Case Difference in PVRR	SCR Capital Cost Estimate	PVRR of SCR and Associated O&M
Brown 1-2	228	154	195
Ghent 2	1,139	232	288
Mill Creek 1-2	1,022	194	260

Black and Veatch estimated the cost of SCRs for Ghent 2 and Mill Creek 1-2 to be $232 million and $194 million, respectively. The PVRRs of these capital costs and the associated incremental operating and maintenance costs assuming a conservatively early 2018 in-service date are $288 million and $260 million, respectively. These values are notably lower than the differences in revenue requirements in

---

[11] Potential future environmental costs also include costs for capping ash ponds related to coal combustion residual regulations. However, these costs will be incurred regardless of whether a unit is retired.

Table 7 for these units, indicating no change to the Companies' decisions for these units as filed in the 2011 Compliance Plan.

In Table 7, Brown 1-2 has the smallest difference in PVRR. Black and Veatch estimated the cost of SCRs for Brown 1 and Brown 2 to be $59 million and $95 million, respectively. The PVRR of these capital costs and the associated incremental operating and maintenance costs assuming a 2018 in-service date is $195 million, which is less than the difference in PVRR for Brown 1-2 in Table 7. Because of their size, installing SCRs on Brown 1-2 would have a limited impact on the Companies' overall NOx emissions and would be the least desirable option for further reducing NO_x emissions.[12] Table 8 compares a forecast of NO_x emissions with and without SCRs on Ghent 2 and Mill Creek 1-2 to the forecast of NO_x allowance allocations. Before the Companies considered installing SCRs on Brown 1-2, allocations of NO_x allowances would have to decrease by more than 40%. The current ozone standard is 0.075 parts per million (ppm). The lowest standard previously contemplated by the EPA (0.060 ppm measured over eight hours) is only 20% lower than the current standard. Furthermore, given CSAPR's system-wide compliance requirements, Brown 1-2 might at most prove to be good candidates for less-costly selective non-catalytic reduction control (SNCR) technology.

Table 8 – NOx Emissions and Allocations

Year	NOx Allowance Allocations	Estimated NOx Emissions (w/o SCRs on Ghent 2 and Mill Creek 1-2)	Estimated NOx Emissions (w/ SCRs on Ghent 2 and Mill Creek 1-2)
2016	26,831	18,536	9,262
2017	26,831	19,353	9,609
2018	26,831	19,885	9,592
2019	26,831	19,486	9,828
2020	26,831	19,987	9,829
2021	26,831	20,004	9,960

2.4 Capital and Fixed O&M Costs

In evaluating the decisions to install controls or retire/replace capacity, the 2011 Compliance Plan analysis considered ongoing capital costs and fixed O&M for routine maintenance at each of the coal units. As these costs increase, the option to retire and replace capacity is favored. Table 9 summarizes the capital and fixed O&M assumptions used in the 2011 Compliance Plan and the amount by which these costs would have to increase to reduce the PVRR difference between installing controls and retirement to zero (breakeven %). For each of the units for which controls are recommended, ongoing capital and fixed O&M could more than double and the Companies' recommendations would remain unchanged.

[12] Installing SCRs on Brown 1-2 would reduce system-wide NOx emissions by approximately 5%.

Table 9 – Capital and Fixed O&M ($M)

	Capital	Fixed O&M			
Unit	**2011**	**2011**	**2012**	**2013**	**Breakeven %**
Brown 1-2	2.0	10	12	11	140%
Brown 3	3.0	16	21	15	270%
Ghent 1	5.4	18	19	18	270%
Ghent 2	5.6	12	18	13	470%
Ghent 3	5.5	18	14	12	390%
Ghent 4	5.5	12	13	12	510%
Mill Creek 1-2	6.6	28	29	28	240%
Mill Creek 3	4.3	18	14	17	280%
Mill Creek 4	5.2	17	19	17	300%
Trimble County 1	1.2	17	15	17	440%

Notes: Capital is escalated at 2.5% after 2011. Fixed O&M is escalated at 2% after 2013.

3 Conclusions

Compared to the 2011 Compliance Plan price forecasts, coal prices in more recently developed price forecasts are relatively more expensive than gas. This narrowing of the margin between coal and natural gas prices further supports the Companies' decision to retire the Cane Run coal units. In addition, the revised estimate for the cost of controls at Cane Run is only slightly lower than the original estimate. For these reasons, the Companies' continue to plan retiring the Cane Run coal units in 2016.

While the Companies' proposal for controls on Brown 1-2 is reasonable, the economics are more sensitive to potential changes in coal and gas prices. Based on the number of years the units would have to operate to justify the cost of controls and the low likelihood that an SCR would be needed on Brown 1-2, the Companies' decision remains reasonable and is unchanged. In addition, the Companies' proposal for controls is supported by fuel price forecasts from PIRA, EIA, and Wood Mackenzie. Only the CERA gas price forecast marginally supports the retirement of Brown 1-2.

The Companies will continue to monitor fuel price trends and other developments that could impact the Brown 1-2 decision.

RECEIVED

SEP 15 2011

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00161**

PETITION OF KENTUCKY UTILITIES COMPANY
FOR CONFIDENTIAL PROTECTION

Kentucky Utilities Company ("KU") hereby petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001 § 7 and KRS 61.878(1)(c) to grant confidential protection for the item described herein, which KU seeks to provide in supplemental response to Commission Staff's First Information Request to KU No. 20(b). In support of this Petition, KU states as follows:

1. Under the Kentucky Open Records Act, the Commission is entitled to withhold from public disclosure commercially sensitive to the extent that open disclosure would permit an unfair commercial advantage to competitors of the entity disclosing the information to the Commission. See KRS 61.878(1)(c). Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. The confidential information contained in the attachment to the cited supplemental response includes KU's projected coal and gas base fuel costs. If the Commission grants public access to this information, KU could be disadvantaged in negotiating fuel contracts in the future, and could also be disadvantaged in the wholesale energy market because fuel costs are important components of energy pricing. All such commercial harms would ultimately harm

KU's customers, who would have to pay higher rates if the disclosed information resulted in higher fuel prices or adversely impacted KU's off-system energy sales.

3. The information for which the Companies are seeking confidential treatment is not known outside of KU and its sister utility, Louisville Gas and Electric Company ("LG&E"), and is not disseminated within KU and LG&E except to those employees with a legitimate business need to know and act upon the information, and is generally recognized as confidential and proprietary information in the energy industry.

4. KU does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, to intervenors with legitimate interests in reviewing the same for the purpose of participating in this case.

5. The Commission has historically given confidential treatment to projected fuel cost information.[1]

6. If the Commission disagrees with this request for confidential protection, it must hold an evidentiary hearing (a) to protect KU's due process rights and (b) to supply the Commission with a complete record to enable it to reach a decision with regard to this matter. Utility Regulatory Commission v. Kentucky Water Service Company, Inc., Ky. App., 642 S.W.2d 591, 592-94 (1982).

7. In accordance with the provisions of 807 KAR 5:001 § 7, KU is filing with the Commission one copy of the Confidential Information highlighted and fifteen (15) copies without the Confidential Information.

---

[1] For example, see the Commission's letter to KU and LG&E (collectively, "Companies") dated May 1, 2008, concerning the Companies' 2008 IRP case (Case No. 2008-00148); the Commission's letter to the Companies dated April 28, 2005, concerning the Companies' 2005 IRP case (Case No. 2005-00162); the Commission's letter to the Companies dated October 24, 2002, concerning the Companies' 2002 IRP case (Case No. 2002-00367); and the Commission's letter to the Companies dated March 6, 2000, concerning the Companies' 1999 IRP case (Case No. 99-430).

WHEREFORE, Kentucky Utilities Company respectfully requests that the Commission grant confidential protection for the information at issue, or in the alternative, schedule and evidentiary hearing on all factual issues while maintaining the confidentiality of the information pending the outcome of the hearing.

Dated: September 14, 2011

Respectfully submitted,

Allyson K. Sturgeon

Kendrick R. Riggs
W. Duncan Crosby III
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202-2828
Telephone: (502) 333-6000

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088

Counsel Kentucky Utilities Company

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Petition for Confidential Protection was served via U.S. mail, first-class, postage prepaid, this 14th day of September 2011, upon the following persons:

Dennis G. Howard II
Lawrence W. Cook
Assistant Attorneys General
Office of the Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Iris G. Skidmore
Bates and Skidmore
415 West Main Street, Suite 2
Frankfort, KY 40601

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

David J. Barberie, Attorney Senior
Leslye M. Bowman, Director of Litigation
Government Center (LFUCG)
Department of Law
200 East Main Street, Suite 1134
Lexington, KY 40507

David C. Brown
Stites & Harbison PLLC
400 West Market Street, Suite 1800
Louisville, KY 40202-3352

Edward George Zuger III
Zuger Law Office PLLC
P.O. Box 728
Corbin, KY 40702

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105

Shannon Fisk
Senior Attorney
Natural Resources Defense Council
2 N. Riverside Plaza, Suite 2250
Chicago, IL 60660

Allyson K. Sturgeon

Counsel for Kentucky Utilities Company