BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN RE: APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2012-00221**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	))))))))	**CASE NO. 2012-00222**

DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2012

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Please state your occupation and employer.

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, the Institute of Management Accounting, and the Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions, including numerous proceedings before the Kentucky Public Service Commission involving Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), Kentucky Power Company, East Kentucky Power Company and Big Rivers Electric Corporation. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service at retail from KU and LG&E (also referred to individually as "Company" or collectively as "Companies").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the KIUC revenue requirement recommendations, address specific issues that affect each Company's revenue requirement; quantify the effects of the depreciation rate recommendations of KIUC witness Mr. Michael Majoros; quantify the effect on the revenue requirements of the return on equity recommendation of KIUC witness Mr. Richard Baudino; and address the issues of short-term debt, including the allocation of short-term debt between base rates and the environmental cost recovery ("ECR") surcharge, and the use by the Companies' owner of debt to finance its equity investment in each of the Companies.

Q. Please summarize your testimony.

A. I recommend that the Commission decrease KU's base rates by at least $13.302 million, a reduction of $95.426 million compared to its revised requested increase of $82.124 million. I recommend that the Commission decrease LG&E's electric base rates by at least $35.209 million, a reduction of $96.790 million compared to its revised requested increase of $61.582 million.

The following table lists each KIUC adjustment and the effect on the claimed revenue deficiency for each Company. The amounts for KU are shown on a Kentucky retail jurisdictional basis and the amounts for LG&E are for electric only. I address in greater detail the reasons for each of the adjustments reflected in the table, except for the adjustment to normalize the Carbide revenues, which is addressed by KIUC witness Mr. Stephen Baron, the depreciation rates, which are addressed by Mr. Majoros, and the return on common equity, which is addressed by Mr. Baudino.

Although Mr. Majoros provides the detailed analyses underlying the KIUC proposed depreciation rates, I address various policy issues related to the correct depreciation rates and the fact that there is no effect on the Companies' earnings. I also quantify the effects of the KIUC recommendations on the depreciation expense included in the revenue requirements.

Similarly, although Mr. Baudino sponsors the KIUC recommendation for the return on common equity, I recommend that the Commission adopt a return that is at or near the low end of the range offered by the Companies and intervenors in order to recognize that the Companies' parent company financed a portion of its equity investment in the Companies with debt. I also note that the return on common equity decided in this proceeding also will affect the return on rate base recovered through the Companies' ECR surcharges based on Commission precedent. Finally, I quantify the effects of the KIUC recommendation on the revenue requirements.

Kentucky Utilities Company and Louisville Gas & Electric Company
Summary of Revenue Requirement Adjustments-Jurisdictional Electric Operations
Recommended by KIUC
Case Nos. 2012-00221 and 2012-00222
For the Test Year Ended March 31, 2012
($ Millions)

	KU Amount	LG&E Amount
Increase Requested by Company	82.124	61.582
KIUC Adjustments:		
Operating Income Issues		
Adjust for Carbide Revenue Normalization		(2.760)
Remove Company's Proforma Adjustment Related to Off-System Sales Margins	(0.189)	(5.763)
Normalize Non-Labor Generation Maintenance Outage Expense	(3.396)	(6.069)
Reduce Normalized Storm Damage Expense	(0.205)	(0.382)
Increase Normalized Injuries and Damages Expense	0.023	0.181
Amortize 2011 Windstorm Regulatory Asset Over Ten Years	-	(0.810)
Reduce Rate Case Amortization Expense	(0.394)	(0.164)
Correct Depreciation Expense	(36.388)	(44.697)
Cost of Capital Issues		
Reduce Capitalization by Amount of Short Term Investment in Money Pool	(4.926)	(5.115)
Reflect Return on Equity of 9.2%	(49.951)	(31.214)
Total KIUC Adjustments to Company Request	(95.426)	(96.790)
KIUC Recommended Change in Base Rates	(13.302)	(35.209)

Further, although I do not recommend an adjustment in this proceeding to impute short-term debt, I note that the Companies' failure to use extremely low-cost short-term debt in lieu of more expensive long-term debt and common equity financing is a recurring concern that the Commission should address in some manner. In conjunction with KIUC's forbearance on a recommendation to impute short-term debt, I recommend that the Commission reconsider the allocation of any future short-term debt between base rates and the ECR. This is essential to ensure that the Companies customers are not shortchanged on the benefits of the savings from any short-term debt that is used to finance the construction of the Companies' upcoming $2.3 billion ECR investment necessary to implement their recently approved ECR plans.

Finally, although I do not directly address the Companies' required return on equity, I urge the Commission to consider the fact that the Company's owner finances its equity investment in the Companies partially with long-term debt and in that manner, arbitrages the equity return on the Companies' equity investment authorized by the Commission. This circumstance is frequently referred to as "double leverage." This fact should influence the Commission toward the lower end of the range of returns on equity that are recommended in this proceeding.

I have structured my testimony into two additional sections consistent with the categories of issues on the preceding table and address each issue in the sequence listed on the preceding table.

II. OPERATING REVENUE AND EXPENSE ISSUES

Carbide Revenue Normalization (LG&E Only)

Q. Have you reflected the Carbide revenue normalization adjustment for LG&E addressed by Mr. Stephen Baron on the table in the Summary section of your testimony?

A. Yes. The quantification shown on the table is slightly higher than computed by Mr. Baron due to the gross-up for bad debt and PSC assessment using the factors shown on Blake Exhibit 1 Reference Schedule 1.34 for each Company.

Off-System Sales Margins

Q. Please describe the Companies' proposed adjustment to reduce the off-

system sales margins from the test year levels.

A. The Companies now propose revised proforma adjustments to reduce the off-system sales ("OSS") margins from the actual test year levels to an annualized level based on the last 3 months of the test year and the first 5 months following the test year. In their initial filings, the Companies proposed annualizations based on the last 3 months of the test year. In his testimony, Company witness Mr. Bellar described these adjustments as "known and measurable changes *during the test year.*" (emphasis added). [Bellar Direct at 6].

However, in their revised filings, the Companies changed the nature of the adjustment to a post-test year adjustment. They now propose a post-test year adjustment based on annualizing the last 3 months of the test year and the first 5 months following the test year. The revised filing represents a fundamental change in the nature of this adjustment from an annualization to a post-test year adjustment, although neither approach is appropriate.

For KU, this has the effect of reducing the actual test year OSS margins from $0.903 million (total Company) to $0.686 million (total Company), a reduction of $0.217 million (total Company), or $0.188 million on a jurisdictional basis. For LG&E, this has the effect of reducing the actual test year OSS margins from $6.945 million to $1.213 million, a reduction of $5.732 million.

Q. Are the Companies' proposed adjustments known and measurable?

A. No. The Companies have presented no compelling evidence that these adjustments are reasonable, let alone known and measurable, or that the adjustments are somehow necessary due to abnormally high margins within the test year. In short, the Companies have not met their burden to demonstrate that the test year margins were abnormal and that any adjustment is necessary. The Companies have provided no quantitative or analytical support whatsoever that the last 3 months of the test year coupled with the first 5 months after the test year represent a better measure for the OSS margins than the actual margins in the test year. For example, the Companies failed to cite any analyses of any specific factor, such as their all-requirements load, the availability of their generating units to sell into the market after meeting that load, or the natural gas prices, that was abnormal in the first nine months of the test year, but not in the last 3 months of the test year or the first 5 months after the test year or in the period when rates will be in effect. The Companies' proposed use of only eight months of actual data also fails to fully address any effects of seasonality on the margins that might occur over a full 12 month test year.

The Companies' transformation of this adjustment from an annualization to a post-test year adjustment presents additional problems. The first of these problems is that the proposed adjustment is a classic example of a selective post-test year adjustment that fails to consider all other adjustments that could have been made to revenues, expenses, and capitalization. In its recent Big Rivers Electric Corporation decision in Case No. 2011-00036, the Commission strictly adhered to the historic test year and rejected the post-test year adjustments proposed by Big Rivers and by KIUC, even those that were known and measurable.

The Commission should be very concerned about adopting selective post-test year adjustments because it compromises the integrity of the ratemaking process and severely disadvantages the other parties. The Companies have steadfastly refused to provide their budgets in response to discovery by other parties in proceeding after proceeding, including this one.[1] Thus, neither the Commission nor any other party can assess the validity of the Companies' proposed post-test year adjustments against the Companies' own budgets for 2012 or other years. This is true for the Companies' proposed proforma OSS margins. Nor can the Commission or any other parties develop or assess the validity of their own selective post-test year adjustments that would reduce the revenue requirements.

The second problem is that the Companies have made no attempt to actually define a post-test year period upon which to base or quantify such a post-test year adjustment or any other post-test year adjustments. Apparently, the Companies envision further updating this post-test year adjustment, essentially proposing a series of real-time post-test year adjustments that will change each month through the pendency of this case. The Commission should decline to adopt this unusual approach to ratemaking.

In addition, I reviewed the Companies' actual OSS margins by month for the period January 2011 through March 2012 provided by KU in response to KIUC 1-41 and LG&E in response to KIUC 1-38 and there is no obvious pattern

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[1] KU response to KIUC 1-40 and LG&E response to KIUC 1-37, a copy of which I have attached as my Exhibit___(LK-2).

to the OSS margins such that any 3 month or longer period could be considered more representative or normal than the actual test year margins. I also reviewed the Companies' explanation of why their initial proposal to annualize a 3 month period represents the going forward OSS margins despite the seasonality and variability of OSS sales and margins that are reflected in the full 12 months in the test year. These explanations were provided by KU in response to KIUC 1-41 and Staff 2-47 and by LG&E in response to KIUC 1-38 and Staff 2-63.

The responses simply reiterated the Companies' general observation through the testimonies of Mr. Bellar and Mr. Thompson that natural gas prices are low and the economy is weak, but did not address the seasonality and other variability in the OSS margins that are reflected in a 12 month period or over longer periods on a cyclical basis. The Companies' general observations are not sufficient to justify this new ratemaking paradigm because these general facts were true during the test year as well and continue to be true since the end of the test year, although natural gas prices have generally trended upward compared to certain months in the test year. I have attached a copy of the Companies' responses to KIUC 1-41 for KU and KIUC 1-38 for LG&E as my Exhibit___(LK-3) and to Staff 2-47 for KU and Staff 2-63 for LG&E as my Exhibit___(LK-4).

Q. Do you have any further comments on the Companies' transformation of this adjustment from a proposed annualization adjustment to a proposed post-test year adjustment?

A. Yes. The position of the Companies is not consistent with that taken in the last case. In Case Nos. 2009-00548 and 2009-00459, I proposed a post-test year adjustment for OSS margins when they were increasing as a defensive offset to various selective post-test year adjustments proposed by the Companies. The Companies vigorously opposed a post-test year adjustment for OSS margins. Mr. Bellar sponsored Rebuttal Testimony wherein he argued that the KIUC post-test year adjustment for OSS margins was not appropriate, not known and measurable, and had never before been adopted by the Commission. He stated the following (Bellar Rebuttal at 6-7):

> **Off-system sales, on the other hand, are not predictable or stable over long periods of time. They are subject to upward and downward cycles that are entirely unpredictable. They are heavily dependent on the economy, the price of fuel, demand for capacity, the relationship between supply and demand characteristics in the region, wheeling costs across transmission systems, and the Company's ability to market power to third parties, none of which can be described as a random variable with a identifiable central tendency.**
>
> **The purpose of a establishing a test year in a rate case is to identify levels of revenues and expenses that are representative on a going forward basis. In offering his adjustment, Mr. Kollen is essentially supplanting what actually occurred during the test year and with his own prediction of what power markets will look like in the future. History has shown that such predictions are unreliable at best. But more significantly, Mr. Kollen's adjustment does not rise to the standard of being known and measurable.**

Q. Do you recommend that the Commission adopt the Companies' proposed proforma adjustments or their newly proposed hybrid approach and real-time quantifications?

A. No. The Companies have not met their burden of proof or demonstrated that the actual OSS margins in the test year were abnormal and nonrecurring or that they should be annualized or replaced with a post-test year adjustment subject to a series of ongoing real-time revisions. The adjustments are not known and measurable. In addition, the Commission should reject the claim for this single selective post-test year adjustment when the Companies have unilaterally limited inquiries into their 2012 budget or any other post-test year adjustments by other parties, thus precluding proposals for other post-test year adjustments that would reduce the revenue requirements. Further, the Commission has consistently used the actual OSS margins in the historic test year for all other utilities, including KU and LG&E, has never adopted the Companies' proposed hybrid approach, and has never adopted a proposal to continually update such a hybrid adjustment in real-time.

<u>Generation Outage Maintenance Expense Should be Normalized</u>

Q. Please describe the generation maintenance expense in the test year and compare it to prior years and projected expense levels.

A. The generation maintenance expense in the test year was greater than in any of the preceding 5 years and is greater than the Companies anticipate when new base rates are effective in 2013. The following table compares the Companies' test year non-labor generation outage expense to the prior 5 years ending March 31. I obtained this information from KU's response to KIUC 2-22 and LG&E's response to KIUC 2-22. I have attached a copy of each of the Companies' responses as my Exhibit___(LK-5).

Non-Labor Generation Maintenance Outage Expenses
($ Millions)

	2007	2008	2009	2010	2011	Test Year Ending 31-Mar-12
KU	8.884	19.958	17.851	9.785	20.166	20.647
LG&E	8.170	15.791	9.189	16.866	15.434	20.903

KU projects that its non-labor generation outage maintenance expense will be $27.503 million in 2012, $11.824 million in 2013 and $29.628 million in 2014, according to its responses to Staff 3-11 (for 2012) and Staff 2-24 (for 2013 and 2014). LG&E projects that its expense will be $15.468 million in 2012, $15.188 million in 2013, and $14.930 million in 2014, according to its responses to Staff 3-30 (for 2012) and KU's response to Staff 2-24 (for 2013 and 2014). I have attached a copy of KU's response to Staff 3-11 and LG&E's response to Staff 3-30 as my Exhibit___(LK-6) and a copy of KU's response to Staff 2-24 as my Exhibit___(LK-7).

Q. Should the Commission normalize the generation outage maintenance expense in the test year?

A. Yes. Due to the variability and magnitude of this expense, I recommend that the Commission normalize it using a methodology similar to that used to normalize storm damage and injuries and damages expense. The actual test year expense was unusually high and will not recur at these levels when rates are reset in 2013, according to the projections provided in response to discovery. The actual expense incurred in the prior years and in the post test years varies depending on the generating units involved and the scope of the maintenance outage activities in any given year. In fact, the expenses in the future actually may decline over time due to the new Black & Veatch Remote Monitoring service, which the Companies expect to improve reliability of the units and optimize maintenance costs, according to Mr. Thompson. [Thompson Direct at 12-13].

Q. Have you quantified the effects of your recommendation?

A. Yes. The effect is to reduce KU's expense by $3.377 million and LG&E's expense by $6.036 million and KU's revenue requirement by $3.396 million and LG&E's revenue requirement by $6.069 million. The computations are detailed on my Exhibit___(LK-8) for KU and my Exhibit___(LK-9) for LG&E.

I used data that was provided by the Companies in KU's response to KIUC 2-22 and LG&E's response to KIUC 2-22 that I previously described. This data was provided on a 12 months ending March 31 basis for each year. I used the same inflation factors to convert the prior year's dollars to current year dollars that the Companies used in their computations of normalized storm damage and injuries and damages expenses as shown on Blake Exhibit Reference Schedules 1.15 and 1.16.

<u>Storm Damage Expense Is Excessive</u>

Q. Please describe the Companies' proposed adjustment to normalize storm

damage expense.

A. The Companies propose an adjustment to normalize storm damage expense in the test year based on the simple average of the inflation-adjusted actual storm damage expenses incurred over the last ten years. The computations of the Companies' adjustments are shown in the revised Blake Exhibit 1 Reference Schedule 1.15.

Q. Have the Companies correctly computed the adjustment?

A. No. The Companies used nine calendar years, from 2003 through 2011, along with the test year to compute the average. The problem is that the calendar year 2011 and the test year share the same 9 months of expense, which effectively double counts the expense that was incurred during those months. There were unusually large expenses during that nine month period, which skewed the Companies' averages upward.

Q. What do you recommend?

A. I recommend that the computations be performed using ten years of actual data with no overlap. That requires the use of data for 12 month periods ending March 31 from March 31, 2003 through March 31, 2012.

Q. What are the effects of your recommendation?

A. The effects are a reduction in expense for KU of $0.204 million and for LG&E of $0.380 million, with related revenue requirement effects for KU of $0.205 million and for LG&E of $0.382 million. The computations are detailed on my Exhibit__(LK-10) for KU and my Exhibit___(LK-11) for LG&E. I obtained the information shown on these exhibits from KU in response to KIUC 2-3 and from LG&E in response to KIUC 2-3. I've included a copy of the KU response as my Exhibit___(LK-12) and the LG&E response as my Exhibit___(LK-13).

<u>Injuries and Damages Expense Is Excessive</u>

Q. Please describe the Companies' proposed adjustment to normalize injuries and damages expense.

A. The Companies propose adjustments to normalize injuries and damages expense in the test year based on the simple average of the inflation-adjusted actual storm damage expenses incurred over the last ten years. The computation of the Companies' adjustments is shown in Blake Exhibit 1 Reference Schedule 1.16.

Q. Have the Companies correctly computed the adjustment?

A. No. The Companies' computations suffer from the same problem as their computations of the storm damage expense. The Companies used nine calendar years, from 2003 through 2011, along with the test year to compute the average. The problem is that the calendar year 2011 and the test year share the same 9 months of expense, which effectively double counts the expense incurred during those months.

Q. What do you recommend?

A. Consistent with my recommendation for storm damage expense, I recommend that the computation be performed using ten years of actual data with no overlap. That requires the use of data for 12 month periods ending March 31 from March 31, 2003 through March 31, 2012.

Q. What are the effects of your recommendation?

A. The effects are an increase in expense for KU of $0.023 million and for LG&E (electric) of $0.180 million, with related revenue requirement effects for KU of $0.023 million and for LG&E of $0.181 million. The computations are detailed on my Exhibit__(LK-14) for KU and my Exhibit___(LK-15) for LG&E. I obtained the information shown on these exhibits from KU in response to KIUC 2-4 and for LG&E in response to KIUC 2-4. I've included a copy of the KU response as my Exhibit___(LK-16) and the LG&E response as my Exhibit___(LK-17).

2011 Wind Storm Amortization Expense Should Reflect 10 Years (LG&E Only)

Q. Please describe LG&E's proposed 2011 Wind Storm amortization expense.

A. LG&E proposes a 5 year amortization of the deferred 2011 Wind Storm costs. The total deferred amount is $8.052 million and the proposed amortization expense is $1.610 million.

Q. Should the Commission use a 5 year amortization period?

A. No. I recommend that the Commission use a 10 year amortization period. A 10 year amortization period minimizes the effect on customers and does not harm the Company. The shorter the amortization period, the more the Company will recover over and above its actual costs. That occurs because the revenue requirement in this proceeding includes a return on the full amount of the deferred costs. As the Company recovers the deferred costs through amortization expense, the Company's financing costs will decline over the amortization period. However, the Company's revenues will not decline until base rates are reset in the next rate proceeding, thus resulting in an overrecovery until that time. This benefit to the Company necessarily harms customers, which the Commission can mitigate simply by using a 10 year amortization period rather than a 5 year period.

In addition to the certain harm to customers from the overrecovery of the financing costs, there is another potential harm to customers. A shorter amortization period, such as the 5 years proposed by the Company could harm customers if the rates including the amortization expense remain in effect for more than 5 years. In that event, the Company will recover more than the amount that it deferred.

Finally, it should be noted that the Commission most recently approved a 10 year amortization period for the deferred 2008 Wind Storm and 2009 Winter Storm costs in Case Nos. 2009-00548 and 2009-00549 pursuant to a settlement agreement that it adopted in those proceedings.

Rate Case Amortization Expense Is Overstated

Q. Please describe the Companies' proposed rate case amortization expense.

A. The Companies' rate case amortization expense includes the remaining deferred 2009 rate case expense plus a three year amortization of the estimated expense for this proceeding. The Companies estimated the remaining deferred 2009 rate case expense as of December 31, 2012 and included only the remaining amount in the test year amortization expense. The Companies provided schedules showing the monthly history since March 2009 and projected through July 2013 of the monthly rate case amortization expense and the unamortized balances for the 2008 and 2009 rate cases for KU in response to Staff 1-55(b) and for LG&E in response to Staff 1-57(b). I have attached a copy of each of these responses as my Exhibit___(LK-18).

Q. Do you agree with the Companies proposed rate case amortization expense?

A. No. The amortization expense for the 2009 case is overstated for two reasons. First, the remaining balance of deferred costs is overstated. Once the deferred 2008 rate case expense was fully amortized, the Companies simply discontinued recognizing that amortization expense instead of applying that expense to the remaining balance of the deferred 2009 rate case expense. In the last base rate case, the revenue requirement included rate case amortization expense for KU of $0.461 million and for LG&E (electric) of $0.248 million related to the 2008 rate case. Using these amounts, the Companies fully amortized the deferred 2008 rate case expenses in February 2012, after which the Companies simply discontinued this amortization expense. In other words, the Companies continued to recover the amortization expense related to the 2008 case, but retained these recoveries for their shareholder rather than reducing the deferred 2009 rate case expense.

Second, the Companies then assumed that the amortization expense for the deferred 2009 rate case expenses would recur even though under the present remaining amortization period, the deferred expense will be fully amortized in July 2013. Under the Companies' proposal, they will overrecover after July 2013 until their next base rate case because they simply will discontinue this amortization expense and will not apply these recoveries to the deferred expenses of these proceedings.

Q. What is your recommendation?

A. I recommend that the Commission provide no further recovery of the Companies' deferred 2009 rate case expenses when rates are reset in this proceeding. The deferred amounts will be fully recovered by the end of this year (except for a *de minimis* amount for KU) if the Commission applies the amounts authorized to recover the deferred 2008 rate case expenses for the March 2012 through December 2012 period.

My recommendation is based on the fact that KU's remaining deferred 2009 rate case expenses will be $0.008 million, or virtually zero and that LG&E's would be negative if not limited to zero. The calculations for KU are shown on my Exhibit___(LK-19) and for LG&E on my Exhibit___(LK-20). The Commission should reject the Companies' position that somehow the rate case expense amortization is "vintaged" by rate case so that they can retain the overrecovery that results when the costs of one rate case are fully amortized and that amortization expense is not continued consistent with the amount of revenues recovered.

If the Commission does not adopt my recommendation to eliminate the amortization of the deferred 2009 rate case expenses, then I recommend that it add the remaining balance to the Companies' estimated rate case expenses in this proceeding and amortization these sums over a 36 month period. In this manner, the Commission can limit the harm to customers from the Companies' proposal to continue recovering this expense even after the deferred amount is fully amortized in June 2013.

Q. Have you quantified the effects of your recommendation?

A. Yes. The elimination of the 2009 rate case amortization expense reduce the KU expense by $0.392 million and the LG&E (electric) expense by $0.163 million. This will reduce KU's revenue requirement effects by $0.394 million and LG&E's (electric) by $0.164 million. The computations for KU are detailed on my Exhibit___(LK-19) and for LG&E (electric) on my Exhibit___(LK-20).

<u>Depreciation Rates and Resulting Depreciation Expense Are Excessive</u>

Q. Please summarize the depreciation adjustments proposed by KIUC.

A. KIUC proposes three changes to the depreciation rates submitted by the Companies. I provide an overview of each of these changes; however, they are addressed in greater detail by KIUC witness Mr. Michael Majoros, who also sponsors the KIUC depreciation rates.

The first change is to remove the Companies' proposed net negative salvage on final retirements (gross plant less interim retirements) for production plant. In their proposed depreciation rates, the Companies have included estimated costs to dismantle their generating units when they are retired even though they have no plans to dismantle the units or to restore the sites to greenfield condition. The Companies' depreciation rates and the depreciation expense included in the revenue requirement should not include recovery of costs that never will be incurred. If for some reason, such costs must or will be incurred in the future, the Commission can authorize recovery at that time.

The second change is to correct the average service lives proposed by the Companies for many of the plant accounts so that they reflect actual interim retirement activity rather than the excessive hypothetical interim retirement activity proposed by Mr. Spanos. Mr. Spanos assumed that future interim retirements would be significantly greater than actual experience in many of the plant accounts, which has the effect of incorrectly reducing the average service lives for those plant accounts. For example, if the actual experience indicated an interim retirement rate of 20%, Mr. Spanos might instead propose an interim retirement rate of 40%, which arbitrarily results in a much shorter average service life for the plant account than the evidence indicates is appropriate.

Mr. Spanos incorporated these assumptions by systematically biasing downward the survivor curves used to simulate the interim retirement history for these plant accounts, meaning that his proposed survivor percentages are much less than the Companies' actual experience. These survivor curves are used to project future interim retirements, and thus, directly affect the average service lives for each account. The greater the interim retirements, the shorter the average service lives. Thus, a systematic downward bias overstates future interim retirements, thus resulting in shorter average service lives and excessive depreciation rates. The systematic bias that results in excessive interim retirements also results in excessive interim net salvage and further compounds the effect on the depreciation rates.

The third change is to correct and reduce the interim net salvage to reflect the effects of the reduction in interim retirements. In addition, the interim net salvage should be applied only to interim retirements, not to total plant. In Case Nos. 2008-00251 and 2008-00252, the Commission adopted a settlement among the parties that adopted the Companies' proposed depreciation rates. Those depreciation rates incorrectly applied the interim net negative salvage to the entirety of the plant balance, rather than only to the interim retirements, which effectively assumed that the interim net negative salvage would apply to the terminal retirements in addition to interim retirements. This was incorrect because the Companies have not dismantled and have no future plans to dismantle their generating units when they are retired.

The Companies now propose a blended net negative salvage rate applied to the entire gross plant weighted between their proposed interim net negative salvage and terminal net negative salvage, which Mr. Spanos now claims is a refinement of his previous methodology. Contrary to this claim, it represents the correction of an error in the depreciation rates that were adopted in the prior cases and that are presently in effect. In this proceeding, KIUC recommends that the Commission reject the Companies' request to include dismantling costs on production plant. The Commission should be careful to ensure that it does not inadvertently extend the interim net salvage beyond interim retirements to include final retirements for production plant.

Q. Please provide an illustration of the effects of the systematic downward bias on the average service lives resulting from selection of survivor curves that do not match the Companies' actual historic data.

A. I will use a new automobile to illustrate these effects and to demonstrate how a downward bias in the survivor curves affects the average service lives used to compute the depreciation rates. In the first instance, I will assume an unbiased analysis by the purchaser of a new automobile and in the second instance, I will assume a downward biased analysis by the purchaser. The first instance is analogous to a correctly performed analysis whereby the survivor curve used to project future interim retirements is fitted as closely as possible to actual historic experience. The second instance is analogous to an improperly performed analysis whereby the survivor curve bears no resemblance to the actual historic experience.

Consider the following illustration of an unbiased analysis. Assume that Jessica buys a new automobile this year. She expects to use it for the next ten years until it is no longer economic to maintain and continue operating. Thus, at the date of purchase, she assumes that the car has a life span of 10 years and a probable retirement date of 2022.

However, based on Jessica's actual experience with her last car, she knows that not every component of the car will survive until its retirement date. Thus, she uses her experience with her last car, along with informed judgment, to project the likely interim retirement experience with her new car. She knows that there will be interim retirements over the ten years of various components due to wear and tear and due to component failure. For example, she knows that the tires likely will need to be replaced every two years, or four times over the life span of the car. She knows that she likely will need to replace the timing belt after eight years.

After processing all this information, she concludes that even though her car has a life span of ten years, it will have an average service life of eight years when she factors in all the interim retirements, and that only 80% of the original cost of the new automobile will "survive" until the retirement date.

Jessica then decides to perform a second analysis in which she negatively biases her assessment. She assumes that the projected interim retirements on the new automobile will be worse than her actual experience with her last automobile. In this biased analysis, she assumes that the tires will need to be replaced every year and a half, the timing belt will need to be replaced after five years, and that there will be other component failures and replacements. After processing this information, she concludes that the car will have an average service life of only six years when all the interim retirements are factored in, and only 60% of the original cost of the new automobile will "survive" until the retirement date.

The depreciation rate under the first analysis will be significantly lower than under the second analysis because the average service life of the automobile properly reflects Jessica's best estimate of the interim retirements and the components of her new automobile that will survive until it is finally retired from service in 2022 and towed to the salvage yard. The depreciation rate under the second analysis necessarily will be overstated because it reflects a pessimistic estimate of interim retirements that is not based on Jessica's actual experience or her best estimate of the interim retirements.

These illustrations demonstrate the importance of selecting the proper survivor curves based on actual historic experience because those selections affect the average service lives of the assets in the depreciation study. If there is a downward bias, then the average service lives are understated, depreciation rates are excessive, and depreciation expense is excessive. In other words, if there is a downward bias, the utility recovers more than necessary to recover the plant costs over the actual service lives of the assets.

Q. The proposed KIUC depreciation rates have a significant effect on the Companies' revenue requirements. Do the proposed KIUC depreciation rates have an effect on the Companies' earnings?

A. No. There is no effect on the Companies' earnings because there is a matching of revenues to recover depreciation expense and the depreciation expense included in the revenue requirements. If the Commission adopts depreciation rates that result in $170 million in depreciation expense, then the amount recovered by the

Companies in their revenues is $170 million. There is no effect on earnings. If the Commission adopts depreciation rates that result in $130 million in depreciation expense, then the amount recovered by the Companies in their revenues is $130 million. Again, there is no effect on earnings.

Q. Should the Commission view adoption of the KIUC proposed depreciation rates as a "disallowance"?

A. No. If depreciation rates and expense are lower, there is no disallowance, the Companies still will recover the entire amount of their plant costs and a return on the undepreciated (unrecovered) costs. There is no question that the Companies will recover the entire amount of their plant costs; the only question is over what period of time they will recover those costs, i.e., what is the best estimate of the average service lives. The important thing is to get the depreciation rates right so that the Companies recover the costs of their plant over the best estimate of their average service lives, no more and no less.

The Companies also include both their gross plant costs (addition) and their accumulated reserve for depreciation (subtraction) in rate base (or capitalization). In this manner, the Companies always earn a rate of return on their undepreciated plant costs. In other words, the return on the undepreciated plant costs ensures that the Companies not only recover the entire amount of their plant costs, they also recover a return on the remaining amount that has not been recovered.

Q. Have you quantified the effects of the KIUC depreciation rates on the Companies' revenue requirements?

A. Yes. The effect is to reduce the depreciation expense by $36.180 million for KU and by $44.459 million for LG&E (electric only), and to reduce the revenue requirement by $36.388 million for KU and by $44.697 million for LG&E. The computations for KU are detailed on my Exhibit___(LK-21) and for LG&E (electric) on my Exhibit___(LK-22). I used the Companies' depreciation workpapers, provided in electronic format response to KIUC 1-29 for KU and KIUC 1-28 for LG&E, but replaced the Companies' proposed depreciation rates with KIUC's proposed rates.

Q. Why are your quantifications different than the quantifications of Mr. Majoros?

A. There are two reasons. First, I computed the depreciation expense using the plant in service at March 31, 2012, the end of the test year, consistent with the manner in which the Companies included depreciation expense in the revenue requirements. Mr. Majoros used the plant in service at December 31, 2011, which was the depreciation study date.

Second, I computed the depreciation expense for KU on a jurisdictional basis, consistent with the amount of depreciation expense included by KU in its revenue requirement. Mr. Majoros computed KU's total Company amount and did not jurisdictionalize it. Consequently, the KU amounts cited in Mr. Majoros' testimony are stated on a total Company basis, including the amounts shown on his table quantifying the effects of each of the proposed KIUC depreciation adjustments.

III. COST OF CAPITAL ISSUES

Capitalization is Overstated Due to Investment in Money Pool

Q. Do both Companies hold investments in the Money Pool?

A. Yes. The Money Pool operates as an intercompany bank whereby the Companies can borrow as needed on a short-term basis from each other or other affiliates or lend their excess funds to each other or other affiliates on a short-term basis. Neither of the Companies borrowed from the Money Pool during the test year, according to KU's response to KIUC 1-15 and LG&E's response to KIUC 1-14.

However, both Companies held so-called short-term investments in the Money Pool during the test year, according to KU's response to KIUC 2-26 and LG&E response to KIUC 2-26. These excess funds were loaned to other affiliates at extremely low interest rates and earned the Companies minimal interest income. These excess funds were not invested in utility assets during the test year and were not used and useful for the provision of utility service.

For the last two years, the Companies' have financed more than they needed to pay for utility investments. Initially, the investments were due to borrowing amounts in excess of actual financing requirements in late 2010, but the Companies have continued to retain excess funds and invest the funds in the Money Pool. The Companies described their initial borrowing in excess of actual financing requirements in response to discovery. The Companies took "advantage of attractive markets in November 2010," replaced all of their "long-term and short-term intercompany debt with long-term debt," and borrowed more than necessary, thus having cash "to use for future working capital and capital expenditure needs," according to KU's response to KIUC 1-35 and LG&E's response to KIUC 1-34. Since then, the Companies could have used any excess funds to reduce their capitalization, but did not do so. They could have avoided additional long-term debt borrowings, avoided equity investments by their parent, or paid dividends to their parent, all of which would have reduced their capitalization, both long-term debt and common equity, but chose not to do so. Instead, the Companies chose to invest the excess funds at extremely low interest rates.

At March 31, 2012, KU held $50.646 million and LG&E held $56.181 million in short-term investments, according to KU's response to KIUC 2-26 and LG&E's response to KIUC 2-26.

I have attached a copy of KU's response to KIUC 1-15 and LG&E's response to KIUC 1-14 as my Exhibit___(LK-23), KU's response to KIUC 2-26 and LG&E's response to KIUC 2-26 as my Exhibit___(LK-24), and KU's response to KIUC 1-35 and LG&E's response to KIUC 1-34 as my Exhibit___(LK-25).

Q. If the Companies did not hold investments in the Money Pool, would their capitalization be lower than shown in the amounts on Blake Exhibit 2 and used to determine the return on component of the revenue requirement?

A. Yes. The investments in the Money Pool are financed by an equivalent amount of capitalization. In other words, the Companies borrowed more and their shareholder invested more so that the Companies could hold investments in the Money Pool and loan these funds to other affiliates. This is analogous to a homeowner borrowing more against his or her home in order to hold amounts in a savings account. The Companies' revenue requirements include a return on their adjusted capitalization, but do not include an offset for the return on the investments held in the Money Pool. Their capitalization should reflect only the amount necessary to fund utility assets, not additional amounts used to invest in non-utility assets or loaned to other affiliates.

Q. Are the Companies' investments in the Money Pool financed only through long-term debt?

A. No. Since their acquisition by PPL, the Companies apparently have adopted a strategy of financing more than they need for utility assets and then loaning these excess funds to other affiliates through the Money Pool instead. At this point, the investments are financed by both long-term debt and common equity financing, not only the excessive borrowing in November 2010. In other words, the source of the funds in the Money Pool no longer can be traced to debt or equity and must be assumed to come from both long-term debt and common equity in the same proportion as the Companies' per books capitalization.

Q. Should the Companies recover a return from ratepayers on their investments in the Money Pool?

A. No. These amounts were not invested in utility assets and are not entitled to a return from customers.

Q. What is your recommendation?

A. I recommend that the Commission reduce the Companies' capitalization by the amount of their investments in the Money Pool at March 31, 2012. I further recommend that the Commission reduce the Company's capitalization on a prorata basis in the same proportion that the Companies request as shown on Blake Exhibit 2 for each Company.

Q. Have you quantified the effects of your recommendation on the Companies' revenue requirements?

A. Yes. The effects are to reduce KU's revenue requirement by $4.926 million and LG&E's revenue requirement by $5.115 million. The computations are detailed on my Exhibit___(LK-26) for KU and on my Exhibit___(LK-27) for LG&E. In Section I of these exhibits, I replicated the Companies' proposed proforma capitalization and costs from Blake Exhibit 2 and then grossed-up the equity component for income taxes. In Section II of each of these exhibits, I reduced the

Companies' long-term debt and common equity for the amount used to finance the investments in the Money Pool on a proportional basis using the March 31, 2012 per books capitalization shown on this exhibit. Finally, I multiplied the Companies' requested grossed-up rate of return times the KU jurisdictional capitalization and LG&E electric total capitalization, respectively, after the removal of the short-term investments. I should note here that the adjustments to capitalization affect only the long-term debt, common equity, and total capitalization amounts and do not affect the weighted cost of capital that is applied to the total capitalization amount.

<u>Short-Term Debt Is Understated</u>

Q. Did the Companies include any short term debt in the debt component of their capitalization as shown on Blake Exhibit 2?

A. No. Neither Company included any short-term debt in their adjusted capitalization as of March 31, 2012, the last day of the test year used in this exhibit. The Companies' capitalization consists only of long-term debt and common equity.

Q. Why does this matter?

A. It matters because short-term debt presently is by far and away the least-cost form of financing available to the Companies. The failure of the Companies either to use short-term debt or to reflect the lower cost of this form of debt in the debt component of their capitalization unnecessarily and inappropriately inflates their cost of capital and their revenue requirements. This is true not only in these proceedings, but also affects the cost of capital and revenue requirement in their Environmental Cost Recovery ("ECR") proceedings.

Q. How does the failure to reflect short-term debt in the cost of capital in the base rate proceedings affect the cost of capital in the ECR proceedings?

A. In the ECR revenue requirement, the overall cost of capital is applied to the Companies' ECR rate base. This effectively allocates the Companies' short-term debt between ECR rate base and their capitalization used for the base rate revenue requirement. Consequently, only a portion of the savings from the Companies' use of short-term debt in the future will flow through the ECR surcharges.

In prior ECR proceedings, KIUC has highlighted the Companies' failure to take advantage of the extremely low cost of short-term debt and the deficiencies in the allocation of any short-term debt between the ECR and base rates using the ratio of ECR rate base to total capitalization. Most recently, I proposed an allocation of actual short-term debt between the ECR and base rates using construction work in progress ("CWIP") instead of rate base and capitalization.[2]

Q. What is the significance of failing to reflect short-term debt in the base rate

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[2] In Case Nos. 2011-00161 and 2011-00162, I proposed that the Commission modify the allocation of short-term debt so that it more closely parallels the Companies' use of short-term debt to finance CWIP. This will have more significance as the Companies' implement their approved environmental compliance plans.

capitalization?

A. When the Companies actually finance with short-term debt, only a portion of the savings will flow through their ECR surcharges. The Companies will retain the entirety of the remainder of the savings, which is by far and away the greater portion of the total. This is inequitable and effectively will provide the Companies with revenues in excess of their costs.

Q. Are the Companies able to finance with short-term debt?

A. Yes. The Companies each have authority from the FERC to issue up to $500 million in short-term debt. [Arbough Direct at 7]. The Companies historically have sourced short-term debt through the Money Pool. The Companies each have entered into a $400 million syndicated credit facility, according to KU's response to KIUC 1-15 and LG&E's response to KIUC 1-14. Pursuant to the terms of their credit facilities, the Companies have the ability to make cash borrowings and to obtain letters of credit. KU also has available a $198 million letter of credit facility. [*Id.*]. The Companies use the credit facilities to support their commercial paper borrowings. In addition, the Companies each have established a commercial paper program and can borrow up to $250 million, according to KU's response to KIUC 1-15 and LG&E's response to KIUC 1-14.

Q. How do the Companies use short-term debt?

A. The Companies use short-term debt to fund capital projects and various working capital requirements, according to KU's response to KIUC 1-34 and LG&E's

response to KIUC 1-33. The Companies fund capital projects initially through short-term debt, up to $250 million, and then issue long-term debt to reduce the amount of short-term debt when market conditions are attractive, according to those same responses to discovery. I have attached a copy of each of these responses as my Exhibit___(LK-28).

Q. How does the cost of short-term debt compare to the Company's cost of long-term debt and its proposed cost of equity?

A The cost of commercial paper is extremely low and is a minute fraction of the cost of either long-term debt or common equity. 30 day paper is 0.13%, 60 day paper is 0.15%, and 90 day paper is 0.20%, according to the September 18, 2012 Wall Street Journal.

The cost of long-term debt requested by KU is 3.69% and by LG&E is 3.81%, according to the revised Blake Exhibit 2. The cost of equity requested by the Companies is 11.0%, which requires customers to pay 17.49% and 17.65% after the gross-up for income taxes for KU and LGE, respectively.

Q. Do you recommend an adjustment to include short-term debt in the capital structure?

A. No. I addressed this issue to stress the importance of using extremely low-cost short-term debt instead of exclusively using long-term debt and common equity to finance construction, which primarily will affect the return on the environmental projects included in the ECR.

I don't recommend an adjustment in this proceeding because I believe that the best approach is the one that I recommended in the ECR proceedings, Case Nos. 2011-00161 and 2011-00162. In those proceedings, I recommended that the Commission change its approach to allocating short-term debt between base rates and ECR rates on rate base/capitalization and instead allocate it on the basis of CWIP, which more closely matches the Companies' actual and/or planned use of short-term debt.

If the Commission does not intend to revisit the allocation issue in the Companies' next ECR proceedings, then it should consider imputing some level of short-term debt in this proceeding. If it does so, then I recommend that the Commission adopt the Companies' proposed debt ratios, but modify the composition of the debt to 10% short-term debt and 90% long-term debt from the Companies' proposed 100% long-term debt. That will result in KU with $161 million in short-term debt (both base rate and ECR) or $152 million (base rate only) and LGE (electric only) with $89 million (both base rate and ECR) or $88 million (base rate only) using the debt amounts shown on Blake Exhibit 2 for each Company. This is a modest proposal and well below each Company's available short-term debt and well below each Company's $250 million short-term debt targeted maximum.

<u>**Cost of Common Equity Should be Reduced**</u>

Q. Have you quantified the revenue requirement effects of the KIUC return on common equity recommendation addressed by Mr. Baudino?

A. Yes. The effect is to reduce KU's revenue requirement by $49.951 million and LG&E's electric revenue requirement by $31.214 million. The computations are detailed in Section III on my Exhibit___(LK-26) for KU and on my Exhibit___(LK-27) for LG&E. In Section III, everything is the same as computed in Section II, except that I changed the return on equity from the 11.0% requested by the Company shown in Section II to the 9.2% recommended by KIUC. I then multiplied the difference in the grossed-up rate of return times KU's jurisdictional and LG&E's electric total capitalization, respectively, as adjusted by KIUC in Section II of these exhibits.

Q. What is the effect on the revenue requirement of each 1.0% return on common equity?

A. For KU, the effect on the revenue requirement of each 1.0% return on common equity is $27.750 million. For LG&E (electric), the effect is $17.341 million.

Q. What is the pretax return on common equity requested by the Companies compared to that recommended by KIUC?

A. The pretax return on common equity requested by KU is 17.49% and by LG&E is 17.65%. The pretax return on common equity recommended by KIUC is 14.63% for KU and 14.77% for LG&E.

The pretax return on common equity includes the authorized return plus the additional return necessary to recover the related federal and state income tax expense. The revenues recovered from customers for the return on equity are subject to income taxes; consequently, the authorized return on equity must be grossed-up for that income tax expense. For this purpose, I included the income tax gross-up to the return on common equity and a gross-up for bad debt and the Commission assessment fee.

Q. Is there another factor that the Commission should consider in conjunction with the return on common equity?

A. Yes. The Companies are owned by LKE. LKE finances its equity investment in the Companies with a combination of debt and equity. Thus, a portion of LKE's equity investment in the Companies actually is financed by debt and not equity even though the Companies are allowed an equity return on their equity capitalization. This structure allows the use of debt at multiple levels of affiliates, thus minimizing the actual parent company equity investment. This use of debt at multiple levels of affiliates is commonly referred to as "double leverage." This financing structure was described by Professor Bonbright in his seminal work: *Principles of Public Utility Rates*, 2nd Edition by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, Public Utility Reports, Inc. (1988), as follows (at 309):

> **The appropriate capital structure to use in the case of a utility owned by a holding company is very controversial...It is particularly controversial when the holding company itself issues debt, and in turn, uses the proceeds of the debt issue to 'buy' equity in its own subsidiaries. The result is called double leverage.**

The concept of double leverage is not to be confused with the concept of consolidated tax savings. Rather, double leverage is a financing issue. Professor Bonbright went on to state (at 392):

> **Use of a consolidated capital structure, however, must be distinguished from the "double leverage" concept. The latter concept "prescribes the use of the cost of total capital (the composite cost of debt and equity) to the parent company as the measure of the cost of common equity to the operating subsidiary."** (citations omitted).

The significance of LKE financing a portion of its equity investments in the Companies is that it is able to use the affiliate structure to earn an equity return, including the gross-up for income taxes, on the portion of its investment that is financed through debt. In this manner, LKE is able to arbitrage the equity returns that the Companies earn against its lower cost of capital.

In addition, LKE is able to deduct the interest expense on its debt for income tax purposes, yet this savings in income tax expense is not flowed down to the Companies or through to the Companies' customers.

Q. Do you recommend that the Commission make a specific adjustment to eliminate the effects of this double leverage either in the Companies' authorized returns or in their income tax expense?

A. Not in this proceeding. However, I recommend that the Commission consider these facts in its determination of the reasonable return on equity.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
3rd day of October 2012.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN RE:	**APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES**	**) CASE NO. 2012-00221**
	APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**) CASE NO. 2012-00222**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2012

EXHIBIT ___ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than thirty years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
as of September 2012**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.

**Expert Testimony Appearances
of
Lane Kollen
as of September 2012**

Date	Case	Jurisdict.	Party	Utility	Subject
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.

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9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.

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12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.

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4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.

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8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.

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01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.

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01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.

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Date	Case	Jurisdict.	Party	Utility	Subject
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.

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08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC.Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service	Artesian Water Co.	Allocation of tax net operating losses between

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Date	Case	Jurisdict.	Party	Utility	Subject
			Commission Staff		regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated programs costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.

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03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in accounts 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in accounts 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-564, 2007-565, 2008-251 2008-252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/09	U-21453, U-20925 U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	U-21453, U-20925 U-22092 (Subdocket J) Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, the Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, including resolution of S02 allowance expense, variable O&M expense, and tiered sharing of off-system sales margins.
04/11 05/11	38306 Direct Supplemental Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company and Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	ER-11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.

**Expert Testimony Appearances
of
Lane Kollen
as of September 2012**

Date	Case	Jurisdict.	Party	Utility	Subject
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including NOL ADIT, bonus depreciation, ADIT, working capital, reserves, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.

EXHIBIT ____ (LK-2)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

**Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012**

Question No. 1-40

Responding Witness: Counsel

Q1-40. Please provide a copy of the Company's operating budget by month for the calendar year 2012. Provide the income statement, balance sheet and cash flow statement.

A1-40. Consistent with its historical practice, the Company does not disclose information relating to budgets. Such projections are only estimates; there is no guarantee that such projections will be realized; and the estimates are based on a number of assumptions that may change over time. The Company has used an historic test year in this proceeding; not a forecasted test year. The Commission determined in its September 6, 1990 Ruling and in its September 21 and October 18, 1990 Orders in Case No. 90-158 that such information is not discoverable in historical test year rate cases. The budgetary information requested in this data request is not relevant to the analysis of known and measurable pro forma adjustments in this case.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-37

Responding Witness: Counsel

Q1-37. Please provide a copy of the Company's operating budget for the calendar year 2012.

A1-37. Consistent with its historical practice, the Company does not disclose information relating to budgets. Such projections are only estimates; there is no guarantee that such projections will be realized; and the estimates are based on a number of assumptions that may change over time. The Company has used an historic test year in this proceeding; not a forecasted test year. The Commission determined in its September 6, 1990 Ruling and in its September 21 and October 18, 1990 Orders in Case No. 90-158 that such information is not discoverable in historical test year rate cases. The budgetary information requested in this data request is not relevant to the analysis of known and measurable pro forma adjustments in this case.

EXHIBIT ____ (LK-3)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-41

Responding Witness: Lonnie E. Bellar

Q1-41. Refer to Exhibit 1 Schedule 1.09.

a. Please provide the computations of the OSS margins for each month January 2009 through the most recent month for which actual data is available using the same definition for OSS margins reflected on this schedule. Show all components of the computations.

b. Please explain why the Company believes that the 3 months January – March 2012 times 4 represents the going forward amount of OSS margins given the seasonality and variability of OSS sales and margins.

A1-41. a. See attachment in Excel format.

b. See the response to PSC 2-47(a).

OSS Margin by Month
$000's
KU

	Jan 2009	Feb 2009	Mar 2009	Apr 2009	May 2009	June 2009	July 2009	Aug 2009	Sept 2009	Oct 2009	Nov 2009	Dec 2009	Jan 2010	Feb 2010	Mar 2010
Sales Volume, MWh															
External Sales	251	365	3,135	4,896	977	357	2,733	1,794	0	4,037	10	447	916	816	146
Intercompany Sales	132,282	62,402	66,631	34,938	102,564	19,981	5,194	7,043	10,613	72,215	49,627	73,948	49,202	134,715	34,646
Total Off-System Volumes	132,533	62,767	69,766	39,834	103,541	20,338	7,927	8,837	10,613	76,252	49,637	74,395	50,118	135,531	34,792
External Sales	$ 19	$ 7	$ 139	$ 168	$ 41	$ 21	$ 110	$ 86	$ -	$ 164	$ 0	$ 21	$ 44	$ 35	$ 6
External Sales, $/MWh	$ 74.00	$ 18.18	$ 44.28	$ 34.41	$ 41.63	$ 58.98	$ 40.30	$ 47.96	$ -	$ 40.68	$ 40.61	$ 46.46	$ 48.32	$ 43.48	$ 41.15
Intercompany Sales	$ 4,782	$ 2,301	$ 2,184	$ 1,090	$ 3,193	$ 676	$ 176	$ 234	$ 330	$ 2,146	$ 1,464	$ 2,397	$ 1,655	$ 4,178	$ 1,064
Intercompany Sales, $/MWh	$ 36.15	$ 36.88	$ 32.77	$ 31.20	$ 31.13	$ 33.83	$ 33.90	$ 33.15	$ 31.12	$ 29.72	$ 29.50	$ 32.42	$ 33.64	$ 31.01	$ 30.71
Transmission	$ -	$ -	$ (70)	$ (187)	$ -	$ -	$ -	$ -	$ -	$ 334	$ (334)	$ -	$ -	$ -	$ -
Off-System Sales	$ 4,801	$ 2,308	$ 2,252	$ 1,072	$ 3,234	$ 697	$ 286	$ 320	$ 330	$ 2,644	$ 1,130	$ 2,418	$ 1,699	$ 4,214	$ 1,070
Cost of Sales															
Fuel Expense	$ 8	$ 12	$ 102	$ 64	$ 32	$ 12	$ 70	$ 42	$ -	$ 127	$ 0	$ 15	$ 31	$ 25	$ 5
Intercompany Fuel Expense	$ 3,861	$ 1,992	$ 1,942	$ 1,005	$ 2,882	$ 605	$ 157	$ 217	$ 309	$ 2,020	$ 1,368	$ 2,258	$ 1,561	$ 3,895	$ 996
External Purchased Power Expense	$ (2)	$ 4	$ 5	$ 48	$ 1	$ 1	$ 23	$ 27	$ 0	$ (3)	$ 0	$ 3	$ 1	$ 2	$ -
Intercompany Purchased Power Expense	$ -	$ -	$ -	$ 39	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission	$ 0	$ 1	$ (57)	$ (41)	$ 264	$ (260)	$ 0	$ 12	$ (0)	$ 118	$ (105)	$ 1	$ 3	$ 2	$ 0
RTO Costs	$ 0	$ (2)	$ 5	$ 1	$ (123)	$ 114	$ 1	$ 0	$ (23)	$ 3	$ (0)	$ 1	$ 2	$ 2	$ 1
Environmental Related Costs	$ 14	$ 1	$ 13	$ 9	$ 30	$ 10	$ 4	$ 4	$ 5	$ 37	$ 22	$ 37	$ 10	$ 45	$ 13
Impact of Lost ECR Revenue	$ 2	$ 1	$ 16	$ 19	$ 6	$ 3	$ 18	$ 12	$ -	$ 26	$ 0	$ 3	$ 8	$ 4	$ 1
Generated for Losses	$ 0	$ 0	$ 0	$ 2	$ 0	$ 0	$ 0	$ 2	$ 0	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0
Total Cost of Sales	$ 3,884	$ 2,008	$ 2,025	$ 1,147	$ 3,091	$ 484	$ 276	$ 317	$ 292	$ 2,331	$ 1,286	$ 2,318	$ 1,616	$ 3,976	$ 1,016
Gross Margin	$ 917	$ 300	$ 227	$ (75)	$ 143	$ 213	$ 10	$ 3	$ 39	$ 314	$ (154)	$ 100	$ 84	$ 237	$ 54

OSS Margin by Month
$000's
KU

	Apr 2010	May 2010	June 2010	July 2010	Aug 2010	Sept 2010	Oct 2010	Nov 2010	Dec 2010	Jan 2011	Feb 2011	Mar 2011	Apr 2011	May 2011	June 2011
Sales Volume, MWh															
External Sales	696	1,856	94	(119)	0	109	1	0	0	326	10,019	1,960	9	13,022	23,681
Intercompany Sales	20,379	39,331	4,557	16,332	14,803	17,468	35,236	36,980	30,373	103,075	116,977	100,968	32,734	86,379	75,035
Total Off-System Volumes	21,075	41,187	4,651	16,213	14,803	17,577	35,237	36,980	30,373	103,401	126,996	102,928	32,743	99,401	98,716
External Sales	$ 22	$ 108	$ 8	$ (39)	$ (0)	$ 5	$ 0	$ -	$ -	$ 16	$ 410	$ 75	$ 0	$ 586	$ 1,155
External Sales, $/MWh	*$ 32.14*	*$ 58.10*	*$ 86.36*	*$ 324.53*	*$ (90.00)*	*$ 44.29*	*$ 53.21*	*$ -*	*$ -*	*$ 50.27*	*$ 40.87*	*$ 38.21*	*$ 48.28*	*$ 44.97*	*$ 48.77*
Intercompany Sales	$ 602	$ 1,104	$ 171	$ 620	$ 527	$ 526	$ 975	$ 1,131	$ 984	$ 3,276	$ 3,475	$ 2,910	$ 949	$ 2,539	$ 2,120
Intercompany Sales, $/MWh	*$ 29.56*	*$ 28.06*	*$ 37.56*	*$ 37.95*	*$ 35.60*	*$ 30.11*	*$ 27.67*	*$ 30.57*	*$ 32.40*	*$ 31.78*	*$ 29.71*	*$ 28.82*	*$ 28.99*	*$ 29.39*	*$ 28.25*
Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Off-System Sales	$ 625	$ 1,211	$ 179	$ 581	$ 527	$ 531	$ 975	$ 1,131	$ 984	$ 3,293	$ 3,885	$ 2,985	$ 949	$ 3,124	$ 3,274
Cost of Sales															
Fuel Expense	$ 18	$ 46	$ 5	$ (0)	$ 0	$ 4	$ -	$ -	$ -	$ 11	$ 281	$ 57	$ 0	$ 393	$ 737
Intercompany Fuel Expense	$ 556	$ 1,081	$ 166	$ 638	$ 514	$ 501	$ 927	$ 1,097	$ 958	$ 3,164	$ 3,315	$ 2,802	$ 911	$ 2,449	$ 2,028
External Purchased Power Expense	$ (0)	$ 2	$ 4	$ (12)	$ 11	$ 8	$ 62	$ 1	$ 101	$ 25	$ 5	$ 5	$ 0	$ 11	$ 9
Intercompany Purchased Power Expense	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ 0	$ 30	$ 46
Transmission	$ (0)	$ 5	$ 2	$ 0	$ 0	$ 1	$ 0	$ 0	$ 0	$ 1	$ 24	$ 6	$ 0	$ 39	$ 84
RTO Costs	$ 1	$ 1	$ 1	$ 1	$ 0	$ 1	$ 9	$ 2	$ 2	$ 1	$ 8	$ 5	$ 2	$ 11	$ 42
Environmental Related Costs	$ 8	$ 15	$ 1	$ 3	$ 3	$ 5	$ 20	$ 12	$ 9	$ 43	$ 79	$ 54	$ 16	$ 48	$ 54
Impact of Lost ECR Revenue	$ (1)	$ 26	$ (2)	$ (6)	$ (0)	$ 1	$ 0	$ -	$ -	$ 0	$ 8	$ 2	$ 0	$ 68	$ 185
Generated for Losses	$ 0	$ 0	$ 0	$ (0)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1	$ 0	$ 4	$ 8
Total Cost of Sales	$ 582	$ 1,177	$ 177	$ 624	$ 528	$ 520	$ 1,017	$ 1,112	$ 1,070	$ 3,245	$ 3,722	$ 2,931	$ 929	$ 3,053	$ 3,194
Gross Margin	$ 43	$ 35	$ 3	$ (43)	$ (1)	$ 10	$ (42)	$ 19	$ (86)	$ 48	$ 163	$ 54	$ 21	$ 72	$ 81

OSS Margin by Month
$000's
KU

	July 2011	Aug 2011	Sept 2011	Oct 2011	Nov 2011	Dec 2011	Jan 2012	Feb 2012	Mar 2012	Apr 2012	May 2012	June 2012
Sales Volume, MWh												
External Sales	12,113	4,811	330	29,353	2,847	539	265	86	108	0	75	4,048
Intercompany Sales	76,982	43,067	90,092	158,275	71,349	120,983	93,872	13,054	17,109	16,506	9,602	13,341
Total Off-System Volumes	89,095	47,878	90,422	187,628	74,196	121,522	94,137	13,140	17,217	16,506	9,677	17,389
External Sales	$ 614	$ 229	$ 14	$ 1,127	$ 116	$ 23	$ 10	$ 4	$ 5	$ -	$ 9	$ 199
External Sales, $/MWh	$ 50.68	$ 47.65	$ 41.37	$ 38.39	$ 40.80	$ 42.31	$ 37.10	$ 42.57	$ 45.73	$ -	$ 119.65	$ 49.05
Intercompany Sales	$ 2,269	$ 1,338	$ 2,445	$ 4,181	$ 1,932	$ 3,323	$ 2,639	$ 403	$ 543	$ 499	$ 317	$ 451
Intercompany Sales, $/MWh	$ 29.48	$ 31.07	$ 27.14	$ 26.41	$ 27.08	$ 27.46	$ 28.11	$ 30.86	$ 31.75	$ 30.22	$ 33.06	$ 33.84
Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Off-System Sales	$ 2,883	$ 1,567	$ 2,458	$ 5,308	$ 2,048	$ 3,345	$ 2,648	$ 406	$ 548	$ 499	$ 326	$ 650
Cost of Sales												
Fuel Expense	$ 396	$ 154	$ 10	$ 799	$ 80	$ 18	$ 7	$ 3	$ 4	$ -	$ 8	$ 128
Intercompany Fuel Expense	$ 2,184	$ 1,298	$ 2,323	$ 3,964	$ 1,864	$ 3,179	$ 2,492	$ 387	$ 521	$ 473	$ 305	$ 439
External Purchased Power Expense	$ 11	$ 3	$ 2	$ 2	$ 1	$ 5	$ 1	$ 2	$ 2	$ 0	$ 0	$ 4
Intercompany Purchased Power Expense	$ 34	$ 7	$ -	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission	$ 49	$ 20	$ 1	$ 96	$ 9	$ 2	$ 1	$ 1	$ 1	$ (2)	$ 0	$ 21
RTO Costs	$ 39	$ 19	$ 1	$ 26	$ 2	$ 3	$ 1	$ 0	$ 0	$ 0	$ 0	$ 5
Environmental Related Costs	$ 10	$ 9	$ 28	$ 59	$ 21	$ 45	$ 32	$ 3	$ 3	$ 3	$ 1	$ 0
Impact of Lost ECR Revenue	$ 68	$ 25	$ 2	$ 128	$ 14	$ 3	$ 1	$ 0	$ 0	$ -	$ 0	$ 3
Generated for Losses	$ 4	$ 2	$ 0	$ 0	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1
Total Cost of Sales	$ 2,795	$ 1,536	$ 2,367	$ 5,076	$ 1,992	$ 3,255	$ 2,535	$ 395	$ 531	$ 474	$ 316	$ 601
Gross Margin	$ 88	$ 31	$ 91	$ 231	$ 56	$ 91	$ 113	$ 11	$ 17	$ 24	$ 12	$ 49

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-38

Responding Witness: Lonnie E. Bellar

Q1-38. Refer to Exhibit 1 Schedule 1.09.

a. Please provide the computations of the OSS margins for each month January 2009 through the most recent month for which actual data is available using the same definition for OSS margins reflected on this schedule. Show all components of the computations.

b. Please explain why the Company believes that the 3 months January – March 2012 times 4 represents the going forward amount of OSS margins given the seasonality and variability of OSS sales and margins.

A1-38. a. See attachment in Excel format.

b. See the response to PSC 2-63(a).

OSS Margin by Month
$000's
LG&E

	Jan 2009	Feb 2009	Mar 2009	Apr 2009	May 2009	June 2009	July 2009	Aug 2009	Sept 2009	Oct 2009	Nov 2009	Dec 2009	Jan 2010	Feb 2010	Mar 2010
Sales Volume, MWh															
External Sales	138,938	64,472	124,046	43,975	121,235	21,904	5,778	10,780	11,115	72,644	50,023	74,916	53,579	148,724	38,742
Intercompany Sales	-	-	-	1,449	-	-	69	-	-	-	-	-	49,202	-	-
Total Off-System Volumes	138,938	64,472	124,046	45,424	121,235	21,904	5,847	10,780	11,115	72,644	50,023	74,916	102,781	148,724	38,742
External Sales	$ 5,930	$ 2,555	$ 4,675	$ 1,534	$ 4,334	$ 1,163	$ 293	$ 498	$ 476	$ 2,677	$ 1,889	$ 3,230	$ 2,469	$ 6,094	$ 1,507
External Sales, $/MWh	*$ 42.68*	*$ 39.64*	*$ 37.69*	*$ 34.88*	*$ 35.75*	*$ 53.10*	*$ 50.69*	*$ 46.20*	*$ 42.82*	*$ 36.85*	*$ 37.76*	*$ 43.11*	*$ 46.08*	*$ 40.98*	*$ 38.89*
Intercompany Sales	$ -	$ -	$ -	$ 39	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Intercompany Sales, $/MWh	$ -	$ -	$ -	*$ 26.63*	$ -	$ -	*$ 31.58*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission	$ -	$ -	$ (633)	$ 349	$ -	$ -	$ -	$ -	$ -	$ 370	$ (370)	$ -	$ -	$ -	$ -
Off-System Sales	$ 5,930	$ 2,555	$ 4,042	$ 1,921	$ 4,334	$ 1,163	$ 295	$ 498	$ 476	$ 3,047	$ 1,519	$ 3,230	$ 2,469	$ 6,094	$ 1,507
Cost of Sales															
Fuel Expense	$ 104	$ 55	$ 1,313	$ 217	$ 297	$ 4	$ 0	$ -	$ 5	$ 1	$ -	$ 11	$ 102	$ 275	$ 83
Intercompany Fuel Expense	$ -	$ -	$ -	$ 36	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
External Purchased Power Expense	$ 101	$ 18	$ 75	$ 13	$ 155	$ 105	$ 30	$ 185	$ 20	$ 21	$ 20	$ 42	$ 27	$ 165	$ 1
Intercompany Purchased Power Expense	$ 4,782	$ 2,301	$ 2,184	$ 1,090	$ 3,193	$ 676	$ 176	$ 234	$ 330	$ 2,146	$ 1,464	$ 2,397	$ 1,655	$ 4,178	$ 1,064
Transmission	$ 437	$ 217	$ (199)	$ 221	$ 324	$ 109	$ 120	$ 83	$ 123	$ 744	$ (330)	$ 240	$ 161	$ 394	$ 125
RTO Costs	$ 169	$ (14)	$ 114	$ 31	$ (1,111)	$ (14)	$ 1	$ 3	$ 23	$ 49	$ 28	$ 64	$ 65	$ 117	$ 32
Environmental Related Costs	$ 16	$ 5	$ 100	$ 7	$ 26	$ 0	$ 0	$ -	$ -	$ 0	$ -	$ -	$ 12	$ 48	$ 17
Impact of Lost ECR Revenue	$ 250	$ 99	$ 191	$ 71	$ 217	$ 64	$ 15	$ 21	$ 18	$ 112	$ 86	$ 150	$ 131	$ 138	$ 27
Generated for Losses	$ 41	$ 21	$ 21	$ 25	$ 33	$ 7	$ 7	$ (1)	$ 3	$ 20	$ 14	$ 23	$ 17	$ 43	$ 11
Total Cost of Sales	$ 5,899	$ 2,701	$ 3,798	$ 1,712	$ 3,134	$ 951	$ 351	$ 524	$ 522	$ 3,094	$ 1,282	$ 2,927	$ 2,171	$ 5,359	$ 1,380
Gross Margin	$ 31	$ (145)	$ 244	$ 209	$ 1,200	$ 212	$ (56)	$ (26)	$ (46)	$ (47)	$ 237	$ 303	$ 298	$ 735	$ 147

OSS Margin by Month
$000's
LG&E

	Apr 2010	May 2010	June 2010	July 2010	Aug 2010	Sept 2010	Oct 2010	Nov 2010	Dec 2010	Jan 2011	Feb 2011	Mar 2011	April 2011	May 2011	June 2011
Sales Volume, MWh															
External Sales	21,734	46,799	6,514	19,734	18,538	20,819	41,717	63,154	54,968	155,967	155,399	139,584	45,552	125,098	96,596
Intercompany Sales	11	6	8	-	-	-	-	-	-	-	29	-	1	882	1,000
Total Off-System Volumes	21,745	46,805	6,522	19,734	18,538	20,819	41,717	63,154	54,968	155,967	155,428	139,584	45,553	125,980	97,596
External Sales	$ 865	$ 2,014	$ 378	$ 1,006	$ 865	$ 820	$ 1,578	$ 2,366	$ 2,441	$ 7,076	$ 6,233	$ 5,028	$ 1,624	$ 4,970	$ 4,114
External Sales, $/MWh	*$ 39.81*	*$ 43.04*	*$ 58.08*	*$ 50.99*	*$ 46.68*	*$ 39.40*	*$ 37.83*	*$ 37.46*	*$ 44.41*	*$ 45.37*	*$ 40.11*	*$ 36.02*	*$ 35.65*	*$ 39.73*	*$ 42.59*
Intercompany Sales	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ 0	$ 30	$ 46
Intercompany Sales, $/MWh	*$ 26.48*	*$ 55.32*	*$ 51.06*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	*$ 26.64*	$ -	*$ 40.88*	*$ 34.08*	*$ 46.23*
Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Off-System Sales	$ 865	$ 2,015	$ 379	$ 1,006	$ 865	$ 820	$ 1,578	$ 2,366	$ 2,441	$ 7,076	$ 6,234	$ 5,028	$ 1,624	$ 5,000	$ 4,161
Cost of Sales															
Fuel Expense	$ 27	$ 162	$ 11	$ 91	$ 80	$ 51	$ 130	$ 516	$ 539	$ 1,264	$ 911	$ 851	$ 286	$ 864	$ 504
Intercompany Fuel Expense	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ 0	$ 28	$ 46
External Purchased Power Expense	$ (15)	$ 61	$ 100	$ 15	$ 70	$ 41	$ 13	$ 31	$ 57	$ 13	$ 18	$ 20	$ 14	$ 57	$ 30
Intercompany Purchased Power Expense	$ 602	$ 1,104	$ 171	$ 620	$ 527	$ 526	$ 975	$ 1,131	$ 984	$ 3,276	$ 3,475	$ 2,910	$ 949	$ 2,539	$ 2,120
Transmission	$ 110	$ 181	$ 90	$ 37	$ 36	$ 109	$ 174	$ 186	$ 167	$ 459	$ 373	$ 410	$ 125	$ 345	$ 340
RTO Costs	$ 14	$ 38	$ 7	$ 16	$ 7	$ 13	$ 59	$ 46	$ 107	$ 240	$ 151	$ 163	$ 88	$ 35	$ 164
Environmental Related Costs	$ 5	$ 14	$ 1	$ 7	$ 6	$ 9	$ 26	$ 64	$ 58	$ 76	$ 74	$ 77	$ 18	$ 72	$ 34
Impact of Lost ECR Revenue	$ (7)	$ 397	$ 0	$ 46	$ 35	$ 35	$ 15	$ 23	$ 21	$ 61	$ 124	$ 101	$ 34	$ 84	$ 87
Generated for Losses	$ 6	$ 13	$ 3	$ 7	$ 7	$ 6	$ 6	$ 6	$ 6	$ 52	$ 52	$ 40	$ 15	$ 35	$ 29
Total Cost of Sales	$ 742	$ 1,969	$ 384	$ 839	$ 768	$ 790	$ 1,397	$ 2,002	$ 1,940	$ 5,442	$ 5,180	$ 4,572	$ 1,529	$ 4,059	$ 3,355
Gross Margin	$ 123	$ 46	$ (5)	$ 167	$ 97	$ 31	$ 181	$ 364	$ 501	$ 1,634	$ 1,054	$ 456	$ 95	$ 941	$ 806

OSS Margin by Month
$000's
LG&E

	July 2011	August 2011	Sept 2011	Oct 2011	Nov 2011	Dec 2011	Jan 2012	Feb 2012	March 2012	April 2012	May 2012	June 2012
Sales Volume, MWh												
External Sales	96,914	49,140	108,549	205,693	207,284	158,719	95,781	13,723	18,827	18,520	12,003	14,332
Intercompany Sales	714	177	-	34	-	-	-	-	-	-	-	-
Total Off-System Volumes	97,628	49,317	108,549	205,727	207,284	158,719	95,781	13,723	18,827	18,520	12,003	14,332
External Sales	$ 4,186	$ 2,176	$ 4,134	$ 7,425	$ 7,764	$ 5,706	$ 3,452	$ 531	$ 790	$ 668	$ 478	$ 702
External Sales, $/MWh	*$ 43.20*	*$ 44.29*	*$ 38.08*	*$ 36.10*	*$ 37.46*	*$ 35.95*	*$ 36.04*	*$ 38.72*	*$ 41.96*	*$ 36.08*	*$ 39.82*	*$ 49.01*
Intercompany Sales	$ 34	$ 7	$ -	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Intercompany Sales, $/MWh	*$ 47.04*	*$ 41.01*	*$ -*	*$ 27.98*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Off-System Sales	$ 4,220	$ 2,183	$ 4,134	$ 7,426	$ 7,764	$ 5,706	$ 3,452	$ 531	$ 790	$ 668	$ 478	$ 702
Cost of Sales												
Fuel Expense	$ 461	$ 160	$ 405	$ 1,020	$ 3,146	$ 861	$ 28	$ 6	$ 31	$ 49	$ 44	$ 12
Intercompany Fuel Expense	$ 33	$ 7	$ -	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
External Purchased Power Expense	$ 63	$ 12	$ 9	$ 12	$ 27	$ 14	$ 13	$ 2	$ 3	$ 1	$ 27	$ 7
Intercompany Purchased Power Expense	$ 2,269	$ 1,338	$ 2,445	$ 4,181	$ 1,932	$ 3,323	$ 2,639	$ 403	$ 543	$ 499	$ 317	$ 451
Transmission	$ 390	$ 204	$ 373	$ 673	$ 626	$ 453	$ 332	$ 142	$ 113	$ 115	$ 36	$ 73
RTO Costs	$ 251	$ 162	$ 143	$ 182	$ 184	$ 157	$ 153	$ 33	$ 33	$ 29	$ 27	$ 22
Environmental Related Costs	$ 32	$ 9	$ 55	$ 171	$ 102	$ 47	$ 1	$ 0	$ 4	$ 6	$ 6	$ 2
Impact of Lost ECR Revenue	$ 89	$ 24	$ 45	$ 81	$ 81	$ 59	$ 34	$ 1	$ 4	$ 2	$ 2	$ 1
Generated for Losses	$ 28	$ 18	$ 31	$ 53	$ 55	$ 45	$ 30	$ 8	$ 8	$ 7	$ 7	$ 9
Total Cost of Sales	$ 3,617	$ 1,934	$ 3,505	$ 6,373	$ 6,152	$ 4,958	$ 3,229	$ 595	$ 740	$ 708	$ 467	$ 576
Gross Margin	$ 604	$ 250	$ 629	$ 1,053	$ 1,612	$ 748	$ 223	$ (64)	$ 50	$ (39)	$ 11	$ 126

EXHIBIT ____ (LK-4)

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request For Information
Dated July 31, 2012

Case No. 2012-00221

Question No. 47

Responding Witness: Lonnie E. Bellar

Q-47. Refer to Blake Exhibit 1, Reference Schedule 1.09, and pages 5-6 of the Testimony of Lonnie E. Bellar ("Bellar Testimony").

a. Explain why the last three months of the test year were selected to form the basis for the proposed adjustment of off-system sales margins as opposed, for example, to the last four months or the last six months.

b. Provide the kWh sales level for the first quarter of 2012 that resulted in off-system sales margins of $141,329 shown on line 1 of Reference Schedule 1.09.

c. On a quarterly basis, for calendar years 2007 through 2011 provide KU's level of off-system sales in kWh and the resulting off-system sales margins.

A-47. a. As discussed in Testimony of Paul W. Thompson on pages 13-16, primarily due to decreased natural gas prices and the weak economy, off-system sales margins have declined significantly. Using the most recent actual data was selected because it reflects a known and measurable level of OSS margins that can be reasonably achieved to establish rates in this case. As indicated in my testimony, the Company is providing monthly updates to the off-system sales margin adjustment (Reference Schedule 1.09) to reflect the most recent actual data. See the response to Question No. 71.

b. 124,494,000 kWh

c. See attached.

Kentucky Utilities
Off-System Sales and Margins

	Sales in kWh	Margins
2007		
Qtr 1	686,186,085	$ 2,949,000
Qtr 2	263,674,939	$ 1,791,000
Qtr 3	237,535,068	$ 1,825,000
Qtr 4	461,040,061	$ 3,535,000
Total	1,648,436,153	$ 10,100,000
2008		
Qtr 1	487,156,060	$ 2,660,000
Qtr 2	519,312,066	$ 2,267,000
Qtr 3	562,291,070	$ 3,137,000
Qtr 4	1,320,448,984	$ 2,195,000
Total	2,889,208,180	$ 10,259,000
2009		
Qtr 1	265,064,960	$ 1,443,652
Qtr 2	163,713,035	$ 280,102
Qtr 3	27,377,016	$ 51,863
Qtr 4	200,284,118	$ 258,878
Total	656,439,129	$ 2,034,496
2010		
Qtr 1	220,441,054	$ 375,343
Qtr 2	66,913,036	$ 80,314
Qtr 3	48,593,019	$ (34,048)
Qtr 4	102,590,009	$ (110,064)
Total	438,537,118	$ 311,545
2011		
Qtr 1	333,325,057	$ 265,067
Qtr 2	230,860,042	$ 173,389
Qtr 3	227,395,048	$ 210,117
Qtr 4	383,346,049	$ 377,901
Total	1,174,926,196	$ 1,026,474

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request For Information
Dated July 31, 2012

Case No. 2012-00222

Question No. 63

Responding Witness: Lonnie E. Bellar

Q-63. Refer to Blake Exhibit 1, Reference Schedule 1.09, and page 10 of the Testimony of Lonnie E. Bellar ("Bellar Testimony").

a. Explain why the last three months of the test year were selected to form the basis for the proposed adjustment of off-system sales margins as opposed, for example, to the last four months or the last six months.

b. Provide the kWh sales level for the first quarter of 2012 that resulted in off-system sales margins of $209,249 shown on line 1 of Reference Schedule 1.09.

c. On a quarterly basis, for calendar years 2007 through 2011 provide LG&E's level of off-system sales in kWh and the resulting off-system sales margins.

A-63. a. As discussed in Testimony of Paul W. Thompson on pages 13-16, primarily due to decreased natural gas prices and the weak economy, off-system sales margins have declined significantly. Using the most recent actual data was selected because it reflects a known and measurable level of OSS margins that can be reasonably achieved to establish rates in this case. As indicated in my testimony, the Company is providing monthly updates to the off-system sales margin adjustment (Reference Schedule 1.09) to reflect the most recent actual data. See the response to Question No. 81.

b. 128,331,000 kWh

c. See attached.

Louisville Gas & Electric
Off-System Sales and Margins

	Sales in kWh		Margins
2007			
Qtr 1	613,751,056	$	5,357,000
Qtr 2	244,065,974	$	965,000
Qtr 3	232,368,932	$	4,465,000
Qtr 4	437,177,940	$	6,196,000
Total	1,527,363,902	$	16,983,000
2008			
Qtr 1	470,571,058	$	4,874,000
Qtr 2	527,241,063	$	7,605,000
Qtr 3	600,564,046	$	6,804,000
Qtr 4	1,235,408,069	$	8,933,000
Total	2,833,784,236	$	28,216,000
2009			
Qtr 1	327,406,055	$	129,176
Qtr 2	188,563,048	$	1,621,099
Qtr 3	27,742,039	$	(127,893)
Qtr 4	197,583,049	$	492,918
Total	741,294,191	$	2,115,300
2010			
Qtr 1	290,237,059	$	1,180,292
Qtr 2	75,068,051	$	164,025
Qtr 3	59,091,041	$	295,322
Qtr 4	159,792,048	$	1,046,129
Total	584,188,199	$	2,685,768
2011			
Qtr 1	450,979,060	$	3,143,834
Qtr 2	269,129,054	$	1,841,576
Qtr 3	255,494,051	$	1,481,698
Qtr 4	571,730,050	$	3,412,939
Total	1,547,332,215	$	9,880,046

EXHIBIT ____ (LK-5)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

**Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012**

Question No. 2.22

Responding Witness: Paul W. Thompson

Q2.22 Refer to page 11 lines 12-15 of Mr. Thompson's Direct Testimony and to the response to KIUC 1-26 related to total maintenance outage expenses.

a. Please provide a schedule in the same format using the 10 years of historic information on a twelve months ending March 31 basis so that there is no overlap between the 2011 calendar year and the 2012 test year reflected in the average.

b. Please separate the annual expense amounts shown on the schedule provided in response to part (a) of this question into payroll, payroll tax loadings, other payroll loadings (benefits expenses), and non-payroll expenses (separate into categories, such as materials and supplies and contractor expenses).

c. Please provide a description of each outage that occurred during the test year.

A2.22 a. See attached. Please note that the information referenced was not averaged.

b. See attached. Please note that the outage expenses do not include any internal employee labor costs. Therefore the breakdown does not include any payroll related costs from internal employees.

c. A description of each planned outage that took place during the test year follows by unit:

- Ghent 1 – Boiler. The primary areas of focus were:
  - Main turbine valve inspections and repairs
  - Chemical clean of high pressure section of the turbine
  - Boiler inspection and repairs
  - Wash air heaters and economizer
  - Boiler inspection and repairs
  - Inspect and repair coal mills

- Ghent 2 – Major including turbine and boiler. The primary areas of focus were:
    - Turbine generator overhaul
    - Turbine system oil flushes
    - Inspect and repair coal mills and gear boxes
    - High energy piping inspection and repairs
    - Boiler chemical clean

  Please note that only a small portion of the Ghent 2 outage actually took place during the test year. Most of the work was done after the test year ended.

- Ghent 3 – Major including turbine and boiler. The primary areas of focus were:
    - Turbine generator overhaul
    - Induced Draft fan motor inspection and repair
    - Boiler inspection and repairs
    - Wash air heaters
    - Boiler chemical clean
    - Inspection and repairs of superheater outlet header
    - Precipitator inspection and repairs
- Ghent 4 – Short, pit stop outage. The primary areas of focus were:
    - Clean condenser tubes
    - Inspect and repair air heaters
    - Boiler inspection and repairs
    - Inspect and repair primary superheat section of boiler
    - Wash Induced Draft fans
    - Inspect and repair circulating water lines.
- Brown 1 – Boiler. The primary areas of focus were:
    - Boiler inspection and repairs
    - Ductwork and precipitator repairs
    - Economizer repairs
- Brown FGD (Scrubber) – Inspection and repairs. The Brown coal units have a common absorber vessel.
- Brown 2 – Boiler. The primary areas of focus were:
    - Boiler inspection and repairs
    - Boiler chemical clean
    - Ductwork repairs
    - Replace expansion joints
- Brown 3 – Boiler. The primary areas of focus were:
    - Boiler inspection and repairs
    - Coal mill maintenance
    - Main condenser vacuum pump overhaul
- Green River 3 – No planned outages during the test year.
- Green River 4 – Boiler. The primary areas of focus were:
    - Boiler inspection and repairs

  - Boiler chemical clean
  - Coal mill overhaul
  - Turbine valve inspection
  - Condensate pump overhaul
- Tyrone 3 – No planned outages during the test year.
- Trimble County 2 – Inspection outage prior to expiration of warranty coverage. The primary areas of focus were:
  - Boiler repairs
  - Air flow testing
  - Wet and dry precipitator inspections
  - Fabric filter inspections
  - Electrical function testing
  - Inspect Low Pressure last stage (turbine) blades
  - Feedwater heater inspections
  - Switchgear maintenance

  Please note that only a small portion of the Trimble County 2 outage actually took place during the test year. Most of the work was done after the test year ended.
- Combustion turbines. None of the combustion turbines had material planned outages during the test year. The costs, or in certain cases, credits that were incurred were for final invoice true-ups and relatively small accounting adjustments.

Twelve Months Ended March 31 KU

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Trimble Co 2	Contractor Expenses	-	-	-	-	-	-	-	-	-	84
	Materials and Supplies	-	-	-	-	-	-	-	-	-	209
	Total	-	-	-	-	-	-	-	-	-	**292**
Total	Contractor Expenses	-	-	-	-	-	-	-	-	-	84
	Materials and Supplies	-	-	-	-	-	-	-	-	-	209
	Total	-	-	-	-	-	-	-	-	-	**292**
Ghent 1	Contractor Expenses	1	1,670	1,171	102	1,723	4,546	2,123	845	1,969	2,768
	Materials and Supplies	84	694	494	399	(673)	841	714	607	1,010	941
	Total	**85**	**2,364**	**1,665**	**501**	**1,050**	**5,387**	**2,837**	**1,452**	**2,979**	**3,709**
Ghent 2	Contractor Expenses	-	4	136	3,152	737	1,746	515	1,712	931	988
	Materials and Supplies	-	20	319	351	196	394	356	462	262	599
	Total	-	**25**	**455**	**3,503**	**933**	**2,140**	**871**	**2,174**	**1,192**	**1,587**
Ghent 3	Contractor Expenses	-	87	219	281	364	2,049	660	796	2,403	7,453
	Materials and Supplies	-	111	11	31	227	200	350	520	919	1,671
	Total	-	**199**	**230**	**312**	**591**	**2,249**	**1,010**	**1,317**	**3,322**	**9,124**
Ghent 4	Contractor Expenses	-	-	570	239	1,218	477	3,856	632	2,584	430
	Materials and Supplies	-	0	5	64	217	287	746	311	862	164
	Total	-	**0**	**575**	**302**	**1,435**	**764**	**4,602**	**943**	**3,446**	**594**
Total	Contractor Expenses	1	1,762	2,096	3,774	4,042	8,818	7,153	3,986	7,886	11,639
	Materials and Supplies	84	825	830	844	(33)	1,722	2,167	1,899	3,053	3,375
	Total	**85**	**2,587**	**2,926**	**4,618**	**4,009**	**10,539**	**9,320**	**5,885**	**10,939**	**15,014**
Brown 1	Contractor Expenses	271	-	431	123	528	2,954	438	175	609	291
	Materials and Supplies	101	2	0	16	180	719	81	53	151	42
	Total	**372**	**2**	**431**	**138**	**707**	**3,674**	**519**	**228**	**760**	**333**
Brown 1, 2, 3	Contractor Expenses	-	-	588	351	271	180	188	-	6	40
	Materials and Supplies	-	19	216	121	331	80	195	-	15	25
	Total	-	**19**	**804**	**471**	**602**	**260**	**383**	-	**21**	**65**
Brown 2	Contractor Expenses	1,516	66	618	504	519	441	1,670	1,181	429	948

Twelve Months Ended March 31 KU

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	Materials and Supplies	329	9	8	168	118	110	301	184	202	214
	Total	**1,845**	**74**	**626**	**672**	**637**	**551**	**1,971**	**1,365**	**631**	**1,162**
Brown 3	Contractor Expenses	-	-	1,221	3,015	892	1,390	797	800	1,097	1,224
	Materials and Supplies	-	-	150	366	572	313	264	475	1,571	603
	Total	-	-	**1,371**	**3,380**	**1,463**	**1,703**	**1,061**	**1,276**	**2,669**	**1,827**
Total	Contractor Expenses	1,786	66	2,859	3,992	2,210	4,966	3,093	2,156	2,142	2,503
	Materials and Supplies	430	30	374	670	1,199	1,222	840	712	1,938	884
	Total	**2,216**	**95**	**3,232**	**4,662**	**3,409**	**6,187**	**3,934**	**2,868**	**4,080**	**3,388**
Green River 3	Contractor Expenses	-	-	(25)	186	269	108	325	440	1,232	-
	Materials and Supplies	-	18	0	31	39	39	103	165	276	(0)
	Total	-	**18**	**(25)**	**217**	**308**	**147**	**428**	**604**	**1,509**	**(0)**
Green River 4	Contractor Expenses	-	-	130	485	263	293	70	643	194	1,448
	Materials and Supplies	-	-	8	36	43	100	57	142	107	487
	Total	-	-	**138**	**521**	**306**	**392**	**127**	**785**	**301**	**1,935**
Total	Contractor Expenses	-	-	105	671	532	401	395	1,083	1,427	1,448
	Materials and Supplies	-	18	9	67	82	139	160	306	383	487
	Total	-	**18**	**113**	**738**	**614**	**540**	**556**	**1,389**	**1,810**	**1,935**
Tyrone 1, 2	Contractor Expenses	-	-	1	-	-	-	-	-	-	-
	Materials and Supplies	-	-	0	-	-	-	-	-	-	-
	Total	-	-	1	-	-	-	-	-	-	-
Tyrone 3	Contractor Expenses	63	849	105	154	146	406	360	-	0	-
	Materials and Supplies	10	163	6	44	65	72	77	-	-	-
	Total	**74**	**1,011**	**111**	**198**	**211**	**478**	**437**	-	0	-
Total	Contractor Expenses	63	849	106	154	146	406	360	-	0	-
	Materials and Supplies	10	163	6	44	65	72	77	-	-	-
	Total	74	**1,011**	**113**	**198**	**211**	**478**	**437**	-	0	-
Total Steam	Contractor Expenses	1,851	2,676	5,166	8,591	6,930	14,591	11,002	7,225	11,455	15,673

Twelve Months Ended March 31 KU

($000s)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	Materials and Supplies	524	1,036	1,218	1,625	1,313	3,154	3,244	2,917	5,375	4,955
	Total	**2,375**	**3,712**	**6,384**	**10,216**	**8,244**	**17,744**	**14,246**	**10,142**	**16,830**	**20,629**
Trimble Co 5	Contractor Expenses	-	-	-	4	283	162	-	-	-	-
	Materials and Supplies	0	0	-	(0)	10	0	-	-	-	-
	Total	**0**	**0**	**-**	**4**	**293**	**162**	**-**	**-**	**-**	**-**
Trimble Co 6	Contractor Expenses	0	-	-	-	-	9	333	-	-	-
	Materials and Supplies	0	0	-	-	-	0	131	-	-	-
	Total	**1**	**0**	**-**	**-**	**-**	**9**	**464**	**-**	**-**	**-**
Trimble Co 7	Contractor Expenses	-	-	-	-	-	8	351	-	-	-
	Materials and Supplies	-	-	-	-	-	1	303	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**9**	**654**	**-**	**-**	**-**
Trimble Co 8	Contractor Expenses	-	-	-	-	-	8	35	(35)	-	-
	Materials and Supplies	-	-	-	-	-	-	18	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**8**	**53**	**(35)**	**-**	**-**
Trimble Co 9	Contractor Expenses	-	-	-	-	-	8	313	-	-	-
	Materials and Supplies	-	-	-	-	0	0	337	-	-	(2)
	Total	**-**	**-**	**-**	**-**	**0**	**8**	**649**	**-**	**-**	**(2)**
Trimble Co 10	Contractor Expenses	-	-	0	-	-	218	103	-	-	-
	Materials and Supplies	-	-	-	-	-	287	1	-	-	-
	Total	**-**	**-**	**0**	**-**	**-**	**505**	**104**	**-**	**-**	**-**
Total	Contractor Expenses	0	-	0	4	283	413	1,134	(35)	-	-
	Materials and Supplies	0	0	-	(0)	10	288	789	-	-	(2)
	Total	**1**	**0**	**0**	**4**	**293**	**700**	**1,924**	**(35)**	**-**	**(2)**
Paddy'S Run 13	Contractor Expenses	-	41	3	-	-	-	99	-	1,943	(18)
	Materials and Supplies	-	3	-	-	-	-	66	-	694	38
	Total	-	45	3	-	-	-	164	-	2,637	20
Brown 5	Contractor Expenses	43	-	-	-	9	-	-	-	101	19

Twelve Months Ended March 31 KU

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	Materials and Supplies	0	-	-	-	-	-	-	-	19	1
	Total	43	-	-	-	9	-	-	-	119	20
Brown 6	Contractor Expenses	35	-	864	2	-	1,307	11	94	333	14
	Materials and Supplies	54	(131)	0	526	-	147	108	(97)	103	(30)
	Total	89	(131)	864	528	-	1,454	119	(2)	437	(16)
Brown 7	Contractor Expenses	22	-	42	15	-	11	1,272	(565)	38	(14)
	Materials and Supplies	8	(972)	54	39	-	-	65	-	3	-
	Total	30	(972)	96	53	-	11	1,337	(565)	41	(14)
Brown 8	Contractor Expenses	45	10	-	-	-	-	-	154	-	-
	Materials and Supplies	0	4	-	-	-	-	-	0	-	-
	Total	45	15	-	-	-	-	-	155	-	-
Brown 9	Contractor Expenses	21	-	-	-	275	-	-	-	-	-
	Materials and Supplies	0	-	-	-	0	-	-	-	-	-
	Total	21	-	-	-	275	-	-	-	-	-
Brown 10	Contractor Expenses	54	-	-	-	-	-	-	-	-	-
	Materials and Supplies	4	-	-	-	-	-	-	-	-	-
	Total	58	-	-	-	-	-	-	-	-	-
Haefling 1	Contractor Expenses	-	-	-	39	-	20	6	19	7	5
	Materials and Supplies	-	-	-	10	-	12	-	15	27	-
	Total	-	-	-	49	-	32	6	34	34	5
Haefling 2	Contractor Expenses	-	-	-	-	-	6	1	13	2	3
	Materials and Supplies	-	-	-	-	-	2	-	6	43	-
	Total	-	-	-	-	-	8	1	20	45	3
Haefling 3	Contractor Expenses	-	-	-	-	44	6	41	29	8	3
	Materials and Supplies	-	-	-	-	19	2	13	7	1	-
	Total	-	-	-	-	64	8	54	36	9	3
Total	Contractor Expenses	220	10	906	56	328	1,351	1,331	(254)	490	29
	Materials and Supplies	66	(1,099)	54	575	19	163	186	(68)	195	(29)
	Total	286	(1,088)	961	631	347	1,514	1,517	(323)	685	0

Twelve Months Ended March 31 KU

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total CTs	Contractor Expenses	221	52	909	60	612	1,763	2,564	(289)	2,433	12
	Materials and Supplies	66	(1,095)	54	574	29	451	1,041	(68)	889	7
	Total	**287**	**(1,044)**	**963**	**634**	**641**	**2,214**	**3,605**	**(357)**	**3,321**	**19**
Dix Dam	Contractor Expenses	-	-	-	-	-	-	-	-	15	-
	Materials and Supplies	-	-	-	-	-	-	-	-	1	-
	Total	-	-	-	-	-	-	-	-	15	-
Grand Total	Contractor Expenses	2,071	2,727	6,075	8,651	7,542	16,354	13,566	6,936	13,902	15,685
	Materials and Supplies	590	(59)	1,273	2,199	1,342	3,604	4,285	2,849	6,264	4,962
	Total	**2,662**	**2,668**	**7,347**	**10,850**	**8,884**	**19,958**	**17,851**	**9,785**	**20,166**	**20,647**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

**Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012**

Question No. 2.22

Responding Witness: Paul W. Thompson

Q2.22 Refer to page 11 lines 12-15 of Mr. Thompson's Direct Testimony and to the response to KIUC 1-25 related to total maintenance outage expenses.

a. Please provide a schedule in the same format using the 10 years of historic information on a twelve months ending March 31 basis so that there is no overlap between the 2011 calendar year and the 2012 test year reflected in the average.

b. Please separate the annual expense amounts shown on the schedule provided in response to part (a) of this question into payroll, payroll tax loadings, other payroll loadings (benefits expenses), and non-payroll expenses (separate into categories, such as materials and supplies and contractor expenses).

c. Please provide a description of each outage that occurred during the test year.

A2.22 a. See attached. Please note that the information referenced was not averaged.

b. See attached. Please note that the outage expenses do not include internal employee labor costs. Therefore the breakdown does not include any payroll related costs from internal employees.

c. A description of each planned outage that took place during the test year follows by unit:

- Cane Run 4 – Major including turbine and boiler. The primary areas of focus were:
  - Turbine overhaul / valves
  - Boiler inspection and repairs
  - Boiler feed pump fluid drive overhaul
  - FGD (Scrubber) piping
- Cane Run 5 – Boiler. The primary areas of focus were:
  - Boiler inspection and repairs

    - Boiler feed pump fluid drive overhaul
    - Boiler feed pump overhaul
    - FGD (Scrubber) mechanical component overhauls
- Cane Run 6 – Boiler. The primary areas of focus were:
    - Boiler inspection and repairs
    - Chemical clean
    - Boiler feed pump motor repair
    - Boiler feed pump overhaul
    - Boiler circulating water pump overhaul
- Mill Creek 1 – Boiler. The primary areas of focus were:
    - Boiler inspection and repair
    - FGD (Scrubber) inspection and repair
- Mill Creek 2 – Major including turbine and boiler. The primary areas of focus were:
    - Turbine generator overhaul
    - Boiler inspection and repairs
    - Precipitator inspection and repairs
    - FGD (Scrubber) inspection and repairs
    - Coal feeder repairs
    - Safety valve repairs
    - Bottom ash system repairs
- Mill Creek 3 – Major including turbine and boiler. The primary areas of focus were:
    - Turbine overhaul
    - Boiler inspection and repairs
    - 4kv motor repairs
    - High energy piping inspections and repairs
    - Precipitator inspection and repairs
    - FGD (Scrubber) inspection and repairs
    - Safety valve repairs
- Mill Creek 4 – Boiler. The primary areas of focus were:
    - Boiler inspection and repairs
    - Cooling tower safety inspections
    - Coal mill inspections and repairs
    - Turbine valve repairs
    - Selective Catalytic Reduction (SCR) performance improvements

Please note that only a very small portion of the Mill Creek 4 outage actually took place during the test year. The vast majority of the work was done after the test year.

- Trimble County 1 – Boiler. The primary areas of focus were:
    - Boiler inspection and repairs
    - Ductwork repairs
    - Turbine driven boiler feed pump overhauls (both A and B sections)
    - Turbine control valve maintenance
    - Precipitator ductwork cleaning

- Trimble County 2 – Inspection outage prior to expiration of warranty coverage. The primary areas of focus were:
  - Boiler repairs
  - Air flow testing
  - Wet and dry precipitator inspections
  - Fabric filter inspections
  - Electrical function testing
  - Inspect Low Pressure last stage (turbine) blades
  - Feedwater heater inspections
  - Switchgear maintenance

  Please note that only a small portion of the Trimble County 2 outage actually took place during the test year. Most of the work was done after the test year ended.
  - Combustion turbines. None of the combustion turbines had material planned outages during the test year. The costs, or in certain cases, credits that were incurred were for final invoice true-ups and relatively small accounting adjustments.

Twelve Months Ended March 31 LGE

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Mill Creek 1	Contractor Expenses	1,510	24	1,933	-	1,288	189	824	192	1,293	570
	Materials and Supplies	337	32	2	-	285	21	277	30	505	63
	Total	1,847	55	1,935	-	1,573	210	1,101	223	1,798	633
Mill Creek 2	Contractor Expenses	25	498	7	1,198	328	1,331	73	1,586	394	3,482
	Materials and Supplies	45	145	129	457	73	475	4	821	32	956
	Total	70	642	136	1,655	401	1,806	77	2,408	425	4,438
Mill Creek 3	Contractor Expenses	1,582	237	275	-	495	1,150	25	1,210	2,922	1,941
	Materials and Supplies	274	280	(0)	6	259	426	301	170	745	677
	Total	1,856	517	275	6	754	1,576	326	1,380	3,667	2,618
Mill Creek 4	Contractor Expenses	-	1,463	1	1,549	1,988	262	1,446	1,592	600	2
	Materials and Supplies	-	328	54	303	122	364	324	661	134	58
	Total	-	1,791	55	1,852	2,110	626	1,771	2,253	734	60
Total	Contractor Expenses	3,117	2,221	2,215	2,747	4,099	2,932	2,368	4,580	5,209	5,995
	Materials and Supplies	656	784	185	765	738	1,286	906	1,683	1,416	1,754
	Total	3,773	3,005	2,400	3,512	4,837	4,218	3,274	6,263	6,624	7,749
Trimble Co 1	Contractor Expenses	150	1,067	74	1,603	209	2,036	193	5,672	13	3,121
	Materials and Supplies	19	221	6	643	109	530	214	1,810	90	1,153
	Total	168	1,288	80	2,246	318	2,565	407	7,482	103	4,274
Trimble Co 2	Contractor Expenses	-	-	-	-	-	-	-	-	-	20
	Materials and Supplies	-	-	-	-	-	-	-	-	-	49
	Total	-	-	-	-	-	-	-	-	-	69
Total	Contractor Expenses	150	1,067	74	1,603	209	2,036	193	5,672	13	3,141
	Materials and Supplies	19	221	6	643	109	530	214	1,810	90	1,202
	Total	168	1,288	80	2,246	318	2,565	407	7,482	103	4,343
Cane Run 4	Contractor Expenses	-	354	1,787	452	693	331	1,925	872	412	4,094
	Materials and Supplies	-	294	8	55	103	175	612	126	101	1,121
	Total	-	648	1,795	506	796	506	2,537	997	513	5,215

Twelve Months Ended March 31 LGE

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Cane Run 5	Contractor Expenses	28	417	165	232	631	4,554	(686)	713	1	1,632
	Materials and Supplies	30	44	35	54	136	679	255	177	57	542
	Total	**58**	**461**	**200**	**287**	**766**	**5,233**	**(432)**	**890**	**58**	**2,174**
Cane Run 6	Contractor Expenses	-	407	11	502	1,011	1,520	894	1,120	3,980	957
	Materials and Supplies	-	46	13	51	312	470	383	481	756	440
	Total	**-**	**452**	**24**	**553**	**1,323**	**1,990**	**1,278**	**1,601**	**4,736**	**1,397**
Total	Contractor Expenses	28	1,178	1,963	1,186	2,334	6,405	2,133	2,705	4,394	6,683
	Materials and Supplies	30	383	56	160	551	1,324	1,251	784	913	2,103
	Total	**58**	**1,561**	**2,019**	**1,347**	**2,885**	**7,729**	**3,383**	**3,488**	**5,307**	**8,786**
Total Steam	Contractor Expenses	3,294	4,466	4,252	5,536	6,642	11,372	4,694	12,957	9,615	15,819
	Materials and Supplies	705	1,388	247	1,568	1,398	3,140	2,371	4,277	2,419	5,059
	Total	**3,999**	**5,854**	**4,499**	**7,105**	**8,041**	**14,513**	**7,064**	**17,234**	**12,034**	**20,878**
Trimble Co 5	Contractor Expenses	-	-	-	2	116	66	-	-	-	-
	Materials and Supplies	0	0	-	(0)	4	0	-	-	-	-
	Total	**0**	**0**	**-**	**2**	**120**	**66**	**-**	**-**	**-**	**-**
Trimble Co 6	Contractor Expenses	0	-	-	-	-	4	136	-	-	-
	Materials and Supplies	0	0	-	-	-	0	54	-	-	-
	Total	**0**	**0**	**-**	**-**	**-**	**4**	**190**	**-**	**-**	**-**
Trimble Co 7	Contractor Expenses	-	-	-	-	-	5	206	-	-	-
	Materials and Supplies	-	-	-	-	-	1	178	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**5**	**384**	**-**	**-**	**-**
Trimble Co 8	Contractor Expenses	-	-	-	-	-	5	20	(20)	-	-
	Materials and Supplies	-	-	-	-	-	-	11	-	-	-
	Total	**-**	**-**	**-**	**-**	**-**	**5**	**31**	**(20)**	**-**	**-**
Trimble Co 9	Contractor Expenses	-	-	-	-	-	5	184	-	-	-
	Materials and Supplies	-	-	-	-	0	0	198	-	-	(1)
	Total	-	-	-	-	0	5	381	-	-	(1)

Twelve Months Ended March 31 LGE

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Trimble Co 10	Contractor Expenses	-	-	0	-	-	128	60	-	-	-
	Materials and Supplies	-	-	-	-	-	168	1	-	-	-
	Total	-	-	0	-	-	296	61	-	-	-
Total	Contractor Expenses	0	-	0	2	116	212	607	(20)	-	-
	Materials and Supplies	0	0	-	(0)	4	169	440	-	-	(1)
	Total	0	0	0	2	120	381	1,047	(20)	-	(1)
Paddy'S Run 13	Contractor Expenses	-	47	3	-	-	-	111	-	2,191	(20)
	Materials and Supplies	-	4	-	-	-	-	74	-	782	43
	Total	-	50	3	-	-	-	185	-	2,973	23
Brown 5	Contractor Expenses	49	-	-	-	10	-	-	-	114	21
	Materials and Supplies	0	-	-	-	-	-	-	-	21	1
	Total	49	-	-	-	10	-	-	-	134	22
Brown 6	Contractor Expenses	22	-	530	1	-	801	7	58	204	9
	Materials and Supplies	33	(81)	0	322	-	90	66	(59)	63	(19)
	Total	54	(81)	530	323	-	891	73	(1)	268	(10)
Brown 7	Contractor Expenses	13	-	26	9	-	7	780	(346)	23	(9)
	Materials and Supplies	5	(595)	33	24	-	-	40	-	2	-
	Total	18	(595)	59	33	-	7	819	(346)	25	(9)
Total	Contractor Expenses	83	-	556	10	10	808	786	(288)	341	21
	Materials and Supplies	38	(676)	33	346	-	90	106	(59)	86	(17)
	Total	121	(676)	589	356	10	898	892	(347)	427	4
Total CTs	Contractor Expenses	84	47	558	12	126	1,019	1,504	(309)	2,532	1
	Materials and Supplies	38	(672)	33	346	4	259	620	(59)	868	24
	Total	122	(626)	592	358	130	1,279	2,124	(368)	3,400	25

Twelve Months Ended March 31 LGE

($000s)		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Dix Dam	Contractor Expenses	-	-	-	-	-	-	-	-	-	-
	Materials and Supplies	-	-	-	-	-	-	-	-	-	-
	Total	-	-	-	-	-	-	-	-	-	-
Grand Total	Contractor Expenses	3,377	4,513	4,811	5,548	6,768	12,392	6,198	12,648	12,147	15,820
	Materials and Supplies	743	716	280	1,914	1,402	3,399	2,991	4,218	3,287	5,084
	Total	**4,120**	**5,229**	**5,091**	**7,463**	**8,170**	**15,791**	**9,189**	**16,866**	**15,434**	**20,903**

EXHIBIT ____ (LK-6)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's Third Request For Information
Dated August 28, 2012

Question No. 11

Responding Witness: Paul W. Thompson

Q-11. Refer to the response to Item 24 of Staff's Second Request. In the same format used in the attachment to the response, provide the maintenance expense incurred by KU in calendar year 2011 and the test year. Also, provide the actual maintenance expense incurred in the first half of 2012 and the projected expense for the remainder of 2012.

A-11. See attached.

Rate Case Analysis - Outages (Nonlabor)

US$ 000

	Actuals 2011	TYE 31-Mar-2012	Actual First Half 2012	Projection Second Half 2012	Projection 2012
Trimble Co 2	233	292	1,126	(63)	1,063
Total	233	292	1,126	(63)	1,063
Ghent 1	1,737	3,709	3,219	30	3,249
Ghent 2	334	1,587	7,912	156	8,068
Ghent 3	9,851	9,124	3,120	(0)	3,120
Ghent 4	402	594	181	2,057	2,238
Total	12,324	15,014	14,433	2,242	16,675
Brown 1	326	333	21	663	684
Brown 1, 2, 3	79	65	6	(0)	6
Brown 2	1,147	1,162	9	639	649
Brown 3	2,003	1,827	50	6,763	6,813
Total	3,555	3,388	86	8,065	8,152
Green River 3	1	(0)	41	972	1,013
Green River 4	1,925	1,935	302	42	344
Total	1,926	1,935	343	1,014	1,357
Tyrone 1, 2	-	-	-	-	-
Tyrone 3	-	-	-	-	-
Total	-	-	-	-	-
Total Steam	18,037	20,629	15,988	11,258	27,246

Rate Case Analysis - Outages (Nonlabor)

US$ 000

	Actuals 2011	TYE 31-Mar-2012	Actual First Half 2012	Projection Second Half 2012	Projection 2012
Trimble Co 5	-	-	-	4	4
Trimble Co 6	-	-	-	4	4
Trimble Co 7	-	-	-	3	3
Trimble Co 8	-	-	-	3	3
Trimble Co 9	(2)	(2)	-	3	3
Trimble Co 10	-	-	-	3	3
Total	(2)	(2)	-	21	21
Paddy'S Run 13	500	20	(5)	26	21
					-
Brown 5	81	20	-	-	-
Brown 6	5	(16)	16	-	16
Brown 7	5	(14)	36	41	77
Brown 8	-	-	-	-	-
Brown 9	-	-	-	50	50
Brown 10	-	-	-	-	-
Haefling 1	3	5	2	10	12
Haefling 2	3	3	-	30	30
Haefling 3	3	3	-	30	30
Total	100	0	55	161	216
Total CTs	598	19	49	208	257
Dix Dam	-				
Grand Total	18,636	20,647	16,038	11,466	27,503

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 30

Responding Witness: Paul W. Thompson

Q-30. Refer to the response to Item 40 of Staff's Second Request. In the same format used in the attachment to the response, provide the maintenance expense incurred by LG&E in calendar year 2011 and the test year. Also, provide the actual maintenance expense incurred in the first half of 2012 and the projected expense for the remainder of 2012.

A-30. See attached.

Rate Case Analysis - Outages (Nonlabor)

US$ 000

	Actual 2011	TYE 31-Mar-2012	Actual First Half 2012	Projection Second Half 2012	Projection 2012
Mill Creek 1	567	633	38	1,450	1,488
Mill Creek 2	22	4,438	5,072	58	5,130
Mill Creek 3	5,403	2,618	138	550	688
Mill Creek 4	579	60	2,526	(13)	2,513
Total	6,571	7,749	7,774	2,045	9,819
Trimble Co 1	4,050	4,274	(123)	0	(123)
Trimble Co 2	55	69	264	(15)	249
Total	4,105	4,343	141	(14)	126
Cane Run 4	609	5,215	4,119	59	4,178
Cane Run 5	2,022	2,174	-	-	-
Cane Run 6	(22)	1,397	1,251	2	1,253
Total	2,609	8,786	5,370	61	5,431
Total Steam	13,285	20,878	13,285	2,092	15,376
Trimble Co 5	-	-	-	2	2
Trimble Co 6	-	-	-	2	2
Trimble Co 7	-	-	-	2	2
Trimble Co 8	-	-	-	2	2
Trimble Co 9	(1)	(1)	-	2	2
Trimble Co 10	-	-	-	2	2
Total	(1)	(1)	-	11	11
Paddy'S Run 13	564	23	(6)	29	23
Brown 5	91	22	-	-	-
Brown 6	3	(10)	10	-	10
Brown 7	3	(9)	22	25	47
Total	98	4	32	25	57
Total CTs	661	25	26	65	91
Dix Dam					
Grand Total	13,946	20,903	13,311	2,157	15,468

EXHIBIT ____ (LK-7)

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request For Information
Dated July 31, 2012

Case No. 2012-00221

Question No. 24

Responding Witness: Paul W. Thompson

Q-24. Refer to page 11, lines 12-17, of the Thompson Testimony.

a. Of the $15 million increase in maintenance expense incurred in the test year compared to the levels reflected in their most recent general rate cases, provide the amount attributed to KU and the amount attributed to its sister company, Louisville Gas and Electric Company ("LG&E").

b. Provide the level of maintenance expense reported by KU due to planned maintenance outages for each of the calendar years from 2006 through 2010.

c. The sentence beginning on line 14 and ending on line 17 indicates that it is expected that the level of maintenance expense incurred in the test year will be incurred again in 2014 and thereafter. Provide the level of maintenance expense expected to be incurred in 2013.

A-24. a. The KU increase was $5,991k and the LG&E increase was $8,590k.

b. See attached.

c. See attached. Please note that the scope of the planned maintenance cycle (e.g., adding more environmental control equipment and aging of all equipment) and the cost of that cycle have increased over past years'. The test year results are indicative of a recurring level of such costs going forward.

Rate Case Analysis - Outages (Nonlabor) KU

US$ 000

	Actual				
	2006	2007	2008	2009	2010
Ghent 1	1,073	5,574	55	2,722	2,379
Ghent 2	918	859	1,132	2,948	1,172
Ghent 3	389	2,334	896	1,117	356
Ghent 4	900	1,006	4,688	995	3,268
Total	3,280	9,772	6,771	7,782	7,175
Brown 1	695	3,563	512	214	697
Brown 1, 2, 3	378	276	349	28	-
Brown 2	626	500	9	3,250	548
Brown 3	1,309	1,716	952	956	2,135
Total	3,008	6,056	1,822	4,448	3,380
Green River 3	315	122	408	496	1,506
Green River 4	300	353	88	789	232
Total	615	475	496	1,285	1,738
Tyrone 1, 2	-	-	-	-	-
Tyrone 3	193	495	438	6	0
Total	193	495	438	6	0
Total Steam	7,096	16,798	9,528	13,520	12,293
Trimble Co 5	-	455	-	-	-
Trimble Co 6	-	9	463	-	-
Trimble Co 7	-	8	654	-	-
Trimble Co 8	-	8	6	12	-
Trimble Co 9	-	8	-	647	-
Trimble Co 10	-	8	601	-	-
Total	-	495	1,725	659	-
Paddy'S Run 13	-	-	164	-	2,159
Brown 5	9	-	-	-	58
Brown 6	(0)	1,453	20	91	400
Brown 7	-	11	1,336	(529)	18
Brown 8	-	-	-	155	-
Brown 9	275	-	-	-	-
Brown 10	-	-	-	-	-
Haefling 1	-	32	6	28	40
Haefling 2	-	8	1	19	45
Haefling 3	64	6	56	36	9
Total	347	1,511	1,420	(200)	570
Total CTs	347	2,006	3,309	459	2,729
Dix Dam	-	-	-	-	15
Grand Total	7,444	18,804	12,836	13,979	15,037

Rate Case Analysis - Outages (Nonlabor)

US$ 000

TOTAL	Projected 2013	Projected 2014
Mill Creek 1	5,500	750
Mill Creek 2	750	3,000
Mill Creek 3	2,770	750
Mill Creek 4	1,500	5,650
Total	10,520	10,150
Trimble Co 1	2,399	-
Trimble Co 2	-	3,340
Total	2,399	3,340
Cane Run 4	-	2,236
Cane Run 5	2,154	-
Cane Run 6	-	1,785
Total	2,154	4,022
Ghent 1	2,205	3,525
Ghent 2	1,565	1,630
Ghent 3	3,115	4,325
Ghent 4	1,680	9,060
Total	8,565	18,540
Brown 1	443	4,540
Brown 1, 2, 3	-	224
Brown 2	647	464
Brown 3	401	942
Total	1,491	6,170
Green River 3	200	1,001
Green River 4	911	301
Total	1,111	1,302
Tyrone 1, 2	-	-
Tyrone 3	-	-
Total	-	-
Total Steam	26,239	43,524
Trimble Co 5	5	6
Trimble Co 6	5	6
Trimble Co 7	5	6
Trimble Co 8	5	6
Trimble Co 9	5	6
Trimble Co 10	5	6
Total	32	33
Paddy'S Run 13	108	111
Brown 5	-	-
Brown 6	77	93
Brown 7	47	48
Brown 8	60	-
Brown 9	355	57
Brown 10	-	596
Haefling 1	31	32
Haefling 2	31	-
Haefling 3	31	64
Total	632	890
Total CTs	772	1,034
Dix Dam	-	-
Grand Total	27,012	44,558

LGE ONLY	Projected 2013	Projected 2014
Mill Creek 1	5,500	750
Mill Creek 2	750	3,000
Mill Creek 3	2,770	750
Mill Creek 4	1,500	5,650
Total	10,520	10,150
Trimble Co 1	2,399	-
Trimble Co 2	-	635
Total	2,399	635
Cane Run 4	-	2,236
Cane Run 5	2,154	-
Cane Run 6	-	1,785
Total	2,154	4,022
Ghent 1	-	-
Ghent 2	-	-
Ghent 3	-	-
Ghent 4	-	-
Total	-	-
Brown 1	-	-
Brown 1, 2, 3	-	-
Brown 2	-	-
Brown 3	-	-
Total	-	-
Green River 3	-	-
Green River 4	-	-
Total	-	-
Tyrone 1, 2	-	-
Tyrone 3	-	-
Total	-	-
Total Steam	15,072	14,806
Trimble Co 5	2	2
Trimble Co 6	2	2
Trimble Co 7	2	2
Trimble Co 8	2	2
Trimble Co 9	2	2
Trimble Co 10	2	2
Total	11	11
Paddy'S Run 13	57	59
Brown 5	-	-
Brown 6	29	35
Brown 7	18	18
Brown 8	-	-
Brown 9	-	-
Brown 10	-	-
Haefling 1	-	-
Haefling 2	-	-
Haefling 3	-	-
Total	47	54
Total CTs	116	124
Dix Dam	-	-
Grand Total	15,188	14,930

KU ONLY	Projected 2013	Projected 2014
Mill Creek 1	-	-
Mill Creek 2	-	-
Mill Creek 3	-	-
Mill Creek 4	-	-
Total	-	-
Trimble Co 1	-	-
Trimble Co 2	-	2,705
Total	-	2,705
Cane Run 4	-	-
Cane Run 5	-	-
Cane Run 6	-	-
Total	-	-
Ghent 1	2,205	3,525
Ghent 2	1,565	1,630
Ghent 3	3,115	4,325
Ghent 4	1,680	9,060
Total	8,565	18,540
Brown 1	443	4,540
Brown 1, 2, 3	-	224
Brown 2	647	464
Brown 3	401	942
Total	1,491	6,170
Green River 3	200	1,001
Green River 4	911	301
Total	1,111	1,302
Tyrone 1, 2	-	-
Tyrone 3	-	-
Total	-	-
Total Steam	11,167	28,718
Trimble Co 5	4	4
Trimble Co 6	4	4
Trimble Co 7	3	3
Trimble Co 8	3	3
Trimble Co 9	3	3
Trimble Co 10	3	3
Total	21	22
Paddy'S Run 13	51	52
Brown 5	-	-
Brown 6	48	58
Brown 7	29	30
Brown 8	60	-
Brown 9	355	57
Brown 10	-	596
Haefling 1	31	32
Haefling 2	31	-
Haefling 3	31	64
Total	585	836
Total CTs	657	910
Dix Dam	-	-
Grand Total	11,824	29,628

EXHIBIT ____ (LK-8)

Kentucky Utilities Company
KIUC Adjustment to Normalize Non-Labor Generation Maintenance Outage Expense
Case No. 2012-00221
For the Test Year Ended March 31, 2012
($ Millions)

Non-Labor Maintenance Outage Expense Based Upon 5 Year Plus Test Year Avg	16.777
Non-Labor Maintenance Outage Expense Incurred During Test Year	20.647
Total Company Adjustment to Normalize Non-Labor Maintenance Outage Expense	(3.870)
Kentucky Jurisdiction	87.257%
Kentucky Jurisdictional Adjustment to Normalize Non-Labor Maintenance Outage Expense	(3.377)
Gross-Up Factor for BD and PSC Assessment Fees	1.005762
Revenue Requirement Effect of Normalizing Non-Labor Maintenance Outage Expense	(3.396)

Year	Expense (a)	CPI-All Urban Consumers	Amount
2012	20.647	1.0000	20.647
2011	20.166	1.0069	20.305
2010	9.785	1.0387	10.164
2009	17.851	1.0558	18.847
2008	19.958	1.0520	20.996
2007	8.884	1.0924	9.705
Total			100.664
Five Year Plus Test Year Average			16.777

(a) All years expense is for the 12 months ended March 31 for each year. See Response to KIUC 2-22.

EXHIBIT ____ (LK-9)

Louisville Gas and Electric Company
KIUC Adjustment to Normalize Non-Labor Generation Maintenance Outage Expense
Case No. 2012-00222
For the Test Year Ended March 31, 2012
($ Millions)

Non-Labor Maintenance Outage Expense Based Upon 5 Year Plus Test Year Avg	14.867
Non-Labor Maintenance Outage Expense Incurred During Test Year	20.903
Adjustment to Normalize Non-Labor Maintenance Outage Expense	(6.036)
Gross-Up Factor for BD and PSC Assessment Fees	1.005358
Revenue Requirement Effect of Normalizing Non-Labor Maintenance Outage Expense	(6.069)

Year	Expense (a)	CPI-All Urban Consumers	Amount
2012	20.903	1.0000	20.903
2011	15.434	1.0069	15.540
2010	16.866	1.0387	17.519
2009	9.189	1.0558	9.702
2008	15.791	1.0520	16.612
2007	8.170	1.0924	8.925
Total			89.201
Five Year Plus Test Year Average			14.867

(a) All years expense is for the 12 months ended March 31 for each year. See Response to KIUC 2-22.

EXHIBIT ____ (LK-10)

Kentucky Utilities Company
KIUC Adjustment to Reduce Normalized Storm Damage Expense
Case No. 2012-00221
For the Test Year Ended March 31, 2012
($ Millions)

	KY Jurisd Amount
Storm Damage Expense Adj Based on 10-Year Average - 12 months Ended March 31 Each Year See amount computed by Company in response to KIUC 2-3a	(0.696)
Storm Damage Expense Adj Based on 10-Year Average - As Revised - Schedule 1.15	(0.492)
Reduction in Normalized Storm Damage Expense Using Annual Data for the 12 months Ended March 31 Each Year	(0.204)
Gross-Up Factor for BD and PSC Assessment Fees	1.005762
Revenue Requirement Effect of Normalizing Storm Damage Expense Using Annual Data for 12 months Ended March 31 Each Year	(0.205)

EXHIBIT ____ (LK-11)

Louisville Gas and Electric Company
KIUC Adjustment to Reduce Normalized Storm Damage Expense
Case No. 2012-00222
For the Test Year Ended March 31, 2012
($ Millions)

	Amount
Storm Damage Expense Adj Based on 10-Year Average - 12 months Ended March 31 Each Year See amount computed by Company in response to KIUC 2-3a	(2.175)
Storm Damage Expense Adj Based on 10-Year Average - As Filed - Schedule 1.15	(1.796)
Reduction in Normalized Storm Damage Expense Using Annual Data for the 12 months Ended March 31 Each Year	(0.380)
Gross-Up Factor for BD and PSC Assessment Fees	1.00536
Revenue Requirement Effect of Normalizing Storm Damage Expense Using Annual Data for	(0.382)

EXHIBIT ____ (LK-12)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.3

Responding Witness: Valerie L. Scott

Q2.3 Refer to Blake Exhibit 1 Schedule 1.15 attached to Mr. Blake's Direct Testimony.

a. Please provide a schedule in the same format using the 10 years of historic information on a twelve months ending March 31 basis so that there is no overlap between the 2011 calendar year and the 2012 test year reflected in the average.

b. Please separate the annual expense amounts shown on the schedule provided in response to part (a) of this question into payroll, payroll tax loadings, other payroll loadings (benefits expenses), and non-payroll expenses (separate into categories, such as materials and supplies and contractor expenses).

A2.3 a. See attached.

b. See attached.

KENTUCKY UTILITIES

Adjustment to Reflect Normalized Storm Damage Expense
For the Twelve Months Ended March 31, 2012

1. Storm damage provision based upon ten year average	$	4,254,374
2. Storm damage expenses incurred during the 12 months ended March 31, 2012		4,994,206
3. Adjustment		(739,832)
4. Kentucky Jurisdiction		94.085%
5. Kentucky Jurisdictional adjustment	$	(696,071)

12 month Period		Expense		CPI-All Urban Consumers		Amount
4/1/2011 thru 3/31/2012	$	4,994,206		1.0000	$	4,994,206
4/1/2010 thru 3/31/2011		2,197,113		1.0332		2,270,058
4/1/2009 thru 3/31/2010		6,886,488	(a)	1.0496		7,228,058
4/1/2008 thru 3/31/2009		5,289,004	(a)	1.0521		5,564,561
4/1/2007 thru 3/31/2008		5,931,453		1.0815		6,414,866
4/1/2006 thru 3/31/2007		3,630,724		1.1169		4,055,156
4/1/2005 thru 3/31/2006		2,649,407		1.1495		3,045,494
4/1/2004 thru 3/31/2005		4,565,829		1.1902		5,434,249
4/1/2003 thru 3/31/2004		1,770,309	(b)	1.2258		2,170,045
4/1/2002 thru 3/31/2003		1,093,372	(a)	1.2503		1,367,044
Total					$	42,543,737
Ten Year Average					$	4,254,374

(a) Periods ending 3/31/2003, 3/31/2009, and 3/31/2010 expenses do not include the 2008 Wind Storm, 2009 Winter Storm, December 2009 Virginia Storm and 2003 Ice Storm that were recorded as were recorded as regulatory assets.

(b) Excludes insurance recovery related to 2003 Ice Storm that was netted against the costs for 4/1/2002 thru 3/31/2003.

Kentucky Utilities

Storm Damage Expenses

12 month Period	Labor	Labor Burdens *	Materials	Material Burdens	Travel, Meals & Other	Outside Services	Net Expense	
4/1/2011 thru 3/31/2012	2,209,583	672,734	54,555	9,432	589,515	1,458,388	4,994,206	
4/1/2010 thru 3/31/2011	941,053	336,271	60,980	8,711	359,705	490,395	2,197,113	
4/1/2009 thru 3/31/2010	1,919,371	478,287	123,060	27,558	742,226	3,595,985	6,886,488	**
4/1/2008 thru 3/31/2009	2,889,305	916,208	66,232	(13,282)	707,204	723,337	5,289,004	
4/1/2007 thru 3/31/2008	2,043,050	601,433	138,310	10,088	703,416	2,435,156	5,931,453	
4/1/2006 thru 3/31/2007	1,370,384	486,407	42,782	6,031	445,516	1,279,605	3,630,724	
4/1/2005 thru 3/31/2006	936,067	265,636	46,875	9,917	227,956	1,162,956	2,649,407	
4/1/2004 thru 3/31/2005	2,800,709	715,077	176,749	15,230	(772,572)	1,630,635	4,565,829	
4/1/2003 thru 3/31/2004	922,608	243,377	79,105	2,041	(18,208)	541,387	1,770,309	
4/1/2002 thru 3/31/2003	485,160	202,731	(50,687)	1,341	(580,943)	1,035,771	1,093,372	

* - Labor burdens include payroll tax loadings and other tax loading as only one burden rate, including taxes and other benefits, is applied to labor.

** - Net expense reported on Blake exhibit 1, reference Schedule 1.15, excluded the entire cost of the December 2009 Winter Storm, however only the costs incurred in Virginia should have been excluded. The costs incurred in Kentucky totaling $3,441,320 have been added to this response.

EXHIBIT ____ (LK-13)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.3

Responding Witness: Valerie L. Scott

Q2.3 Refer to Blake Exhibit 1 Schedule 1.15 attached to Mr. Blake's Direct Testimony.

a. Please provide a schedule in the same format using the 10 years of historic information on a twelve months ending March 31 basis so that there is no overlap between the 2011 calendar year and the 2012 test year reflected in the average.

b. Please separate the annual expense amounts shown on the schedule provided in response to part (a) of this question into payroll, payroll tax loadings, other payroll loadings (benefits expenses), and non-payroll expenses (separate into categories, such as materials and supplies and contractor expenses).

A2.3 a. See attached.

b. See attached.

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Normalized Storm Damage Expense
For the Twelve Months Ended March 31, 2012

		Electric
1.	Storm damage provision based upon ten year average	$ 5,510,352
2.	Storm damage expenses incurred during the 12 months ended March 31, 2012	7,685,591
3.	Adjustment	$ (2,175,239)

12 month Period	Expense		CPI-All Urban Consumers	Amount
4/1/2011 thru 3/31/2012	$ 7,685,591	(a)	1.0000	$ 7,685,591
4/1/2010 thru 3/31/2011	1,943,180		1.0332	2,007,694
4/1/2009 thru 3/31/2010	3,056,306	(a)	1.0496	3,207,898
4/1/2008 thru 3/31/2009	4,971,617	(a)	1.0521	5,230,639
4/1/2007 thru 3/31/2008	5,534,610		1.0815	5,985,680
4/1/2006 thru 3/31/2007	5,367,275		1.1169	5,994,709
4/1/2005 thru 3/31/2006	2,134,612		1.1495	2,453,736
4/1/2004 thru 3/31/2005	14,039,110		1.1902	16,709,349
4/1/2003 thru 3/31/2004	2,318,678		1.2258	2,842,235
4/1/2002 thru 3/31/2003	2,388,218		1.2503	2,985,989
Total				$ 55,103,520
Ten Year Average				$ 5,510,352

(a) 2008, 2009, and 2011 expenses do not include 2008 Wind storm, 2009 Winter storm, and 2011 Summer storm expenses that were recorded as regulatory assets.

Louisville Gas and Electric

Storm Damage Expenses

12 month Period	Labor	Labor Burdens *	Materials	Material Burdens	Travel, Meals & Other	Outside Services	Net Expense
4/1/2011 thru 3/31/2012	1,914,254	893,638	303,287	3,051	583,046	3,988,316	7,685,591
4/1/2010 thru 3/31/2011	598,711	261,979	20,067	1,224	162,359	898,840	1,943,180
4/1/2009 thru 3/31/2010	723,166	317,548	151,000	624	224,284	1,639,682	3,056,306
4/1/2008 thru 3/31/2009	1,924,504	648,629	129,081	(5,528)	584,412	1,690,519	4,971,617
4/1/2007 thru 3/31/2008	1,346,434	454,640	264,538	9,792	566,955	2,892,249	5,534,610
4/1/2006 thru 3/31/2007	1,154,986	388,150	441,186	21,002	538,824	2,823,126	5,367,275
4/1/2005 thru 3/31/2006	679,095	256,461	93,017	5,123	288,489	812,425	2,134,612
4/1/2004 thru 3/31/2005	2,677,045	880,715	191,045	256	781,378	9,508,671	14,039,110
4/1/2003 thru 3/31/2004	700,302	283,637	72,560	708	220,069	1,041,402	2,318,678
4/1/2002 thru 3/31/2003	736,808	220,536	67,347	3,666	302,177	1,057,685	2,388,218

* - Labor burdens Include payroll tax loadings and other tax loading as only one burden rate, including taxes and other benefits, is applied to labor

EXHIBIT ____ (LK-14)

Kentucky Utilities Company
KIUC Adjustment to Increase Normalized Injuries and Damages Expense Acct 925
Case No. 2012-00221
For the Test Year Ended March 31, 2012
($ Millions)

	KY Jurisd Amount
Injuries and Damages Expense Adj Based on 10-Year Average - 12 months Ended March 31 Each Year (See amount computed by Company in response to KIUC 2-4a)	(1.210)
Injuries and Damages Expense Adj Based on 10-Year Average - As Filed - Schedule 1.16	(1.233)
Increase in Injuries and Damages Expense Using Annual Data for the 12 months Ended March 31 Each Year	0.023
Gross-Up Factor for BD and PSC Assessment Fees	1.005762
Revenue Requirement Effect of Normalizing Injuries and Damages Expense Using Annual Data for 12 months Ended March 31 Each Year	0.023

EXHIBIT ____ (LK-15)

Louisville Gas and Electric Company
KIUC Adjustment to Increase Normalized Injuries and Damages Expense Acct 925
Case No. 2012-00222
For the Test Year Ended March 31, 2012
($ Millions)

	Amount
Injuries and Damages Expense Adj Based on 10-Year Average - 12 months Ended March 31 Each Year (See amount computed by Company in response to KIUC 2-4a)	(0.199)
Injuries and Damages Expense Adj Based on 10-Year Average - As Filed - Schedule 1.16	(0.379)
Increase in Injuries and Damages Expense Using Annual Data for the 12 months Ended March 31 Each Year	0.180
Gross-Up Factor for BD and PSC Assessment Fees	1.005358
Revenue Requirement Effect of Normalizing Injuries and Damages Expense Using Annual Data for 12 months Ended March 31 Each Year	0.181

EXHIBIT ____ (LK-16)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.4

Responding Witness: Valerie L. Scott

Q2.4 Refer to Blake Exhibit 1 Schedule 1.16 attached to Mr. Blake's Direct Testimony.

a. Please provide a schedule in the same format using the 10 years of historic information on a twelve months ending March 31 basis so that there is no overlap between the 2011 calendar year and the 2012 test year reflected in the average.

b. Please separate the annual expense amounts shown on the schedule provided in response to part (a) of this question into payroll, payroll tax loadings, other payroll loadings (benefits expenses), and non-payroll expenses (separate into categories, such as materials and supplies and contractor expenses).

A2.4 a. See attached.

b. See attached.

Exhibit 1
Reference Schedule 1.16
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for Injuries and Damages FERC Account 925
For the Twelve Months Ended March 31, 2012

1. Injury/Damage provision based upon ten year average	$	2,200,118
2. Injury/Damage expenses incurred during the 12 months ended March 31, 2012		3,560,504
3. Adjustment		(1,360,386)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		88.938%
5. Kentucky Jurisdictional adjustment	$	(1,209,900)

Year	Amount (a)	CPI-All Urban Consumers	Adjusted Amount
2012	$ 3,560,504	1.0000	$ 3,560,504
2011	2,472,598	1.0332	2,554,688
2010	1,889,331	1.0496	1,983,042
2009	1,333,991	1.0521	1,403,491
2008	1,183,390	1.0815	1,279,837
2007	1,653,007	1.1169	1,846,243
2006	2,241,016	1.1495	2,576,048
2005	1,148,875	1.1902	1,367,391
2004	1,764,588	1.2258	2,163,031
2003	2,612,900	1.2503	3,266,909
Total			$ 22,001,184
Ten Year Average			$ 2,200,118

(a) 2012 - 2003 expense is for 12 months ended March 31.

KENTUCKY UTILITIES

Injuries and Damages Expenses FERC Account 925

For Annual Periods Ending as of March 31

Year	Public Liability	Auto Liability	Other Injuries and Damages	Safety and Industrial Health Supplies	Safety and Industrial Health Labor	Safety and Industrial Health Labor Loadings(a)	Workers Compensation Loadings	Total
2012	2,124,725	181,189	344,147	16,071	58,318	15,770	820,284	3,560,504
2011	1,847,815	59,139	146,918	6,231	10,431	72,537	329,527	2,472,598
2010	1,219,188	183,843	25,813	13,184	59,809	16,217	371,176	1,889,231
2009	970,970	51,538	23,318	7,474	88,413	26,593	165,685	1,333,991
2008	886,322	(9,002)	43,324	4,115	86,889	29,077	142,665	1,183,390
2007	794,043	76,882	7,698	9,554	89,079	31,392	644,359	1,653,007
2006	805,931	85,697	(21,169)	38,365	113,811	33,799	1,184,582	2,241,016
2005	1,083,400	73,730	134,467	48,002	106,059	28,718	(325,502)	1,148,875
2004	442,644	77,343	252,147	29,395	80,797	19,410	862,852	1,764,588
2003	696,197	161,536	718,862	63,844	70,372	14,299	887,790	2,612,900

(a) The Company does not maintain the payroll tax loading separate from other labor loadings (burdens). Accordingly, only total labor burdens are provided.

EXHIBIT ____ (LK-17)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.4

Responding Witness: Valerie L. Scott

Q2.4 Refer to Blake Exhibit 1 Schedule 1.16 attached to Mr. Blake's Direct Testimony.

a. Please provide a schedule in the same format using the 10 years of historic information on a twelve months ending March 31 basis so that there is no overlap between the 2011 calendar year and the 2012 test year reflected in the average.

b. Please separate the annual expense amounts shown on the schedule provided in response to part (a) of this question into payroll, payroll tax loadings, other payroll loadings (benefits expenses), and non-payroll expenses (separate into categories, such as materials and supplies and contractor expenses).

A2.4 a. See attached.

b. See attached.

Exhibit 1
Reference Schedule 1.16
Sponsoring Witness: Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Injuries and Damages FERC Account 925
For the Twelve Months Ended March 31, 2012

	Electric	Gas
1. Injury/Damage provision based upon ten year average	$ 2,249,187	$ 497,833
2. Injury/Damage expenses incurred during the 12 months ended March 31, 2012	2,448,360	621,607
3. Adjustment	$ (199,173)	$ (123,774)

Year	Electric (a)	Gas (a)	CPI-All Urban Consumers	Adjusted Electric	Adjusted Gas
2012	$ 2,448,360	$ 621,607	1.0000	$ 2,448,360	$ 621,607
2011	2,222,293	564,621	1.0332	2,296,074	583,367
2010	901,491	228,276	1.0496	946,205	239,599
2009	1,584,225	453,890	1.0521	1,666,764	477,538
2008	2,232,794	354,640	1.0815	2,414,767	383,543
2007	1,731,351	463,379	1.1169	1,933,746	517,548
2006	2,488,038	668,106	1.1495	2,860,000	767,988
2005	1,669,759	390,950	1.1902	1,987,347	465,308
2004	1,366,002	373,801	1.2258	1,674,446	458,205
2003	3,410,511	370,811	1.2503	4,264,162	463,625
Total				$ 22,491,871	$ 4,978,328
Ten Year Average				$ 2,249,187	$ 497,833

(a) 2003 - 2012 expense is for 12 months ended March 31.

LOUISVILLE GAS AND ELECTRIC COMPANY

Injuries and Damages Expenses FERC Account 925

For Annual Periods Ending as of March 31

Year	Public Liability	Auto Liability	Other Injuries and Damages	Safety and Industrial Health Supplies	Safety and Industrial Health Labor	Safety and Industrial Health Labor Loadings(a)	Workers Compensation Loadings	Total	Electric	Gas
2012	1,457,376	189,033	339,420	23,016	55,909	13,645	991,568	3,069,967	2,448,360	621,607
2011	1,254,002	91,542	98,622	25,189	50,908	15,296	1,251,354	2,786,914	2,222,293	564,621
2010	1,392,166	49,840	36,436	18,741	49,469	12,007	(428,891)	1,129,767	901,491	228,276
2009	1,252,088	116,785	27,932	22,830	46,940	19,368	552,172	2,038,115	1,584,225	453,890
2008	2,000,486	47,568	48,129	20,938	53,550	22,951	393,813	2,587,434	2,232,794	354,640
2007	1,098,459	38,201	6,482	67,682	64,148	17,602	902,156	2,194,730	1,731,351	463,379
2006	1,062,410	40,372	(197,101)	31,704	63,979	26,302	2,128,478	3,156,144	2,488,038	668,106
2005	1,154,258	67,462	36,343	28,059	42,259	13,855	718,472	2,060,709	1,669,759	390,950
2004	786,384	26,948	69,751	7,378	25,351	10,128	813,863	1,739,803	1,366,002	373,801
2003	1,619,719	11,641	1,101,449	6,205	17,516	6,237	1,018,555	3,781,322	3,410,511	370,811

(a) The Company does not maintain the payroll tax loading separate from other labor loadings (burdens). Accordingly, only total labor burdens are provided.

EXHIBIT ____ (LK-18)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Commission Staff's First Request for Information
Dated June 15, 2012

Question No. 55

Responding Witness: Lonnie E. Bellar

Q-55. Provide the following information concerning the costs for the preparation of this case:

a. A detailed schedule of expenses incurred to date for the following categories:

(1) Accounting;
(2) Engineering;
(3) Legal;
(4) Consultants; and
(5) Other Expenses (Identify separately).

For each category, the schedule should include the date of each transaction, check number or other document reference, the vendor, the hours worked, the rates per hour, amount, a description of the services performed, and the account number in which the expenditure was recorded. Provide copies of any invoices, contracts, or other documentation that support charges incurred in the preparation of this rate case. Indicate any costs incurred for this case that occurred during the test year.

b. An itemized estimate of the total cost to be incurred for this case. Expenses should be broken down into the same categories as identified in (a) above, with an estimate of the hours to be worked and the rates per hour. Include a detailed explanation of how the estimate was determined, along with all supporting workpapers and calculations.

c. During the course of this proceeding, provide monthly updates of the actual costs incurred, in the manner requested in (a) above. Updates will be due the last business day of each month, through the month of the public hearing.

A-55. a. See attached. The Company has transitioned to all-electronic billing through Serengeti for outside legal services and no longer receives paper invoices. Therefore, supporting documentation from Serengeti is provided in the attachment that includes the above requested information for legal services.

b. See attached.

c. The Company will provide monthly updates as requested.

KENTUCKY UTILITIES
CASE NO. 2012-00221
Schedule of Ratecase Preparation Costs
Response to Commission's Order
Dated June 15, 2012
Question No. 55(b)
Responding Witness: Lonnie E. Bellar

LINE NO				
1	ESTIMATED EXPENSES			
2	VENDOR	RATE	TOTAL UNITS	TOTAL ESTIMATED
3	LEGAL	$ 238.00	1,681	$ 400,000.00
4	CONSULTANTS	200.00	575	115,000.00
5	NEWSPAPER ADVERTISING			1,500,000.00
6	PRINTING COSTS & OTHER SUPPLIES			15,000.00
7	TOTAL PROJECTED COST			$ 2,030,000.00

Note: Estimate of 2012 Rate Case expenses are based upon the recoverable 2009 Rate Case expense.

Recoverable 2009 Rate Case Expenses		
Legal	$	376,082.42
Consultants		154,248.50
Newspaper Advertising		1,468,650.20
Printing Costs & other Supplies		15,521.88
Total	$	2,014,503.00

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's First Request for Information
Dated June 15, 2012

Question No. 57

Responding Witness: Lonnie E. Bellar

Q-57. Provide the following information concerning the costs for the preparation of this case:

a. A detailed schedule of expenses incurred to date for the following categories:

(1) Accounting;
(2) Engineering;
(3) Legal;
(4) Consultants; and
(5) Other Expenses (Identify separately).

For each category, the schedule should include the date of each transaction, check number or other document reference, the vendor, the hours worked, the rates per hour, amount, a description of the services performed, and the account number in which the expenditure was recorded. Provide copies of any invoices, contracts, or other documentation that support charges incurred in the preparation of this rate case. Indicate any costs incurred for this case that occurred during the test year.

b. An itemized estimate of the total cost to be incurred for this case. Expenses should be broken down into the same categories as identified in (a) above, with an estimate of the hours to be worked and the rates per hour. Include a detailed explanation of how the estimate was determined, along with all supporting workpapers and calculations.

c. During the course of this proceeding, provide monthly updates of the actual costs incurred, in the manner requested in (a) above. Updates will be due the last business day of each month, through the month of the public hearing.

A-57. a. See attached. The Company has transitioned to all-electronic billing through Serengeti for outside legal services and no longer receives paper invoices. Therefore, supporting documentation from Serengeti is provided in the attachment that includes the above requested information for legal services.

b. See attached.

c. The Company will provide monthly updates as requested.

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2012-00222
Schedule of Ratecase Preparation Costs
Response to Commission's Order
Dated June 15, 2012
Question No. 57(b)
Responding Witness: Lonnie E. Bellar

LINE NO				
1	ESTIMATED EXPENSES			
2	VENDOR	RATE	TOTAL UNITS	TOTAL ESTIMATED
3	ELECTRIC			
4	LEGAL	$ 238.00	1,113	$ 265,000.00
5	CONSULTANTS	200.00	350	70,000.00
6	NEWSPAPER ADVERTISING			545,000.00
7	PRINTING COSTS & OTHER SUPPLIES			10,000.00
8	TOTAL ELECTRIC			890,000.00
9	GAS			
10	LEGAL	$ 238.00	651	$ 155,000.00
11	CONSULTANTS	200.00	200	40,000.00
12	NEWSPAPER ADVERTISING			300,000.00
13	PRINTING COSTS & OTHER SUPPLIES			5,000.00
14	TOTAL GAS			500,000.00
15	TOTAL PROJECTED COST			$ 1,390,000.00

Note: Estimate of 2012 Rate Case expenses are based upon the recoverable 2009 Rate Case expense.

Recoverable 2009 Rate Case Expenses	
Electric	
Legal	$ 239,292.15
Consultants	98,102.04
Newspaper Advertising	492,203.08
Printing Costs & other Supplies	9,871.94
Total Electric	839,469.21
Gas	
Legal	136,913.76
Consultants	56,146.46
Newspaper Advertising	281,701.13
Printing Costs & other Supplies	5,649.98
Total Gas	480,411.33
Total	$ 1,319,880.54

EXHIBIT ____ (LK-19)

Kentucky Utilities Company
KIUC Adjustment to Reduce Rate Case Amortization Expense
Case No. 2012-00221
For the Test Year Ended March 31, 2012
($ Millions)

		Amount
2008 Rate Case Expense Amortization Expense Discontinued But Remaining in Rates		(0.384)
See Response to Staff 1-55 (b)		
March 2012	0.038	
April 2012	0.038	
May 2012	0.038	
June 2012	0.038	
July 2012	0.038	
Aug 2012	0.038	
September 2012	0.038	
October 2012	0.038	
November 2012	0.038	
December 2012	0.038	
Total	0.384	
Unamortized Balance of 2009 Rate Case Regulatory Asset at December 31, 2012		0.392
Remaining 2009 Rate Case Regulatory Asset at December 31, 2012 Assuming Continued 2008 Rate Case Amortization Expense Applied to 2009 Rate Case Balance. This relatively small amount was not added to 2012 expense.		0.008
2012 Rate Case Expense Estimated by the Company in This Proceeding - As Revised		1.586
Remaining Rate Case Expenses to be Amortized		1.586
Amortization Period in Years		3
Amortization Per Year		0.529
Amount of Test Year Amortization Computed by Company - Schedule 1.23		0.920
KIUC Adjustment to Reduce Rate Case Amortization Expense		(0.392)
Gross-Up Factor for BD and PSC Assessment Fees		1.005762
Revenue Requirement Effect of Reducing Rate Case Amortization Expense		(0.394)

EXHIBIT ____ (LK-20)

Louisville Gas & Electric Company
KIUC Adjustment to Reduce Rate Case Amortization Expense
Case No. 2012-00222
For the Test Year Ended March 31, 2012
($ Millions)

		Amount
2008 Rate Case Expense Amortization Expense Discontinued But Remaining in Rates		(0.206)
See Response to Staff 1-57 (b)		
March 2012	0.021	
April 2012	0.021	
May 2012	0.021	
June 2012	0.021	
July 2012	0.021	
Aug 2012	0.021	
September 2012	0.021	
October 2012	0.021	
November 2012	0.021	
December 2012	0.021	
Total	0.206	
Unamortized Balance of 2009 Rate Case Regulatory Asset at December 31, 2012		0.163
Remaining 2009 Rate Case Regulatory Asset at December 31, 2012 Assuming Continued 2008 Rate Case Amortization Expense Applied to 2009 Rate Case Balance		(0.043)
Since 100% of the Remaining 2009 Rate Case balance was exhausted, use zero going forward		
2012 Rate Case Expense Estimated by the Company in This Proceeding - As Revised		0.848
Remaining Rate Case Expenses to be Amortized		0.848
Amortization Period in Years		3
Amortization Per Year		0.283
Amount of Test Year Amortization Computed by Company - Schedule 1.23		0.446
KIUC Adjustment to Reduce Rate Case Amortization Expense		(0.163)
Gross-Up Factor for BD and PSC Assessment Fees		1.005358
Revenue Requirement Effect of Reducing Rate Case Amortization Expense		(0.164)

EXHIBIT ____ (LK-21)

KIUC Adjusted Exhibit 1
Reference Schedule 1.12

KENTUCKY UTILITIES

Adjustment To Reflect Annualized Depreciation Expenses
At March 31, 2012

	As Filed	As Adjusted	KIUC Adjustment
1. Annualized direct depreciation expense under proposed rates	$ 144,441,326	$ 116,129,556	
2. Annualized depreciation for 2005 and 2006 ECR plans to be eliminated	45,422,676	32,270,892	
3. Total annualized depreciation expense	$ 189,864,002	$ 148,400,448	
4. Depreciation expense per books for test year	$ 192,192,743	$ 192,192,743	
5. Depreciation expense for asset retirement costs (ARO)	(3,077,746)	(3,077,746)	
6. Depreciation for environmental cost recovery (ECR) plans (1)	(67,949)	(67,949)	
7. Depreciation booked above the line for below the line items (2)	(84)	(84)	
8. Depreciation expense per books excluding ARO and ECR	$ 189,046,964	$ 189,046,964	
9. Total Adjustment to reflect annualized depreciation expense (Line 3 - Line 7)	817,038	(40,646,516)	
10. Kentucky Jurisdiction (Ref. Sch. Allocators)	87.257%	87.257%	
11. Kentucky Jurisdictional adjustment	$ 712,919	$ (35,466,746)	$ (36,179,665)

(1) Reflects the elimination of the 2005 and 2006 ECR Plans. Only reflects ECR plan amounts which will continue after effective date of new base rates in this proceeding.
(2) See response to AG 2-9.

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

	Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
Intangible Plant						
301	Organization	$	44,456	0.00%	$	-
302	Franchises and Consents		55,919	18.88%		10,559
303	Miscellaneous Intangible Plant - Software		19,760,083	15.18%		2,998,745
303.1	Customer Care Solution Software		40,343,675	9.94%		4,009,179
	Total Intangible Plant	$	60,204,133		$	7,018,483
Steam Production Plant						
310.00	Land	$	10,881,104	0.00%	$	-
311.00	Structures and Improvements					
	5603 Tyrone Unit 3		5,607,062	1.65%		92,407
	5604 Tyrone Units 1&2		583,381	1.65%		9,614
	5613 Green River Unit 3		2,821,437	1.65%		46,499
	5614 Green River Unit 4		5,476,054	1.65%		90,248
	5615 Green River Units 1&2		2,560,764	1.65%		42,203
	5621 Brown Unit 1		4,703,190	1.65%		77,511
	5622 Brown Unit 2		2,208,657	1.65%		36,400
	5623 Brown Unit 3		21,608,590	1.65%		356,120
	5630 Brown Unit 1,2,3 Scrubber		43,955,566	1.65%		724,410
	5643 Pineville Unit 3		16,204	1.65%		267
	5651 Ghent Unit 1		18,818,852	1.65%		310,144
	5650 Ghent Unit 1 Scrubber		8,436,673	1.65%		139,041
	5652 Ghent Unit 2		16,011,013	1.65%		263,870
	5658 Ghent Unit 2 Scrubber		15,817,338	1.65%		260,678
	5653 Ghent Unit 3		42,177,126	1.65%		695,100
	5654 Ghent Unit 4		31,022,092	1.65%		511,260
	0321 Trimble County Unit 2		106,881,880	1.65%		1,761,467
	0322 Trimble County Unit 2 Scrubber		5,522,307	1.65%		91,010
	5591 System Laboratory		824,969	1.65%		13,596
		$	335,053,155	1.65%	$	5,521,845

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
312.00 Boiler Plant Equipment					
5603 Tyrone Unit 3	$	13,989,313	2.54%	$	355,344
5604 Tyrone Units 1&2		421,900	2.54%		10,717
5613 Green River Unit 3		12,145,770	2.54%		308,516
5614 Green River Unit 4		25,264,653	2.54%		641,750
5615 Green River Units 1&2		349,298	2.54%		8,873
5621 Brown Unit 1		45,946,145	2.54%		1,167,083
5622 Brown Unit 2		40,993,123	2.54%		1,041,271
5623 Brown Unit 3		144,532,013	2.54%		3,671,274
5630 Brown Unit 1,2,3 Scrubber		332,297,548	2.54%		8,440,727
5643 Pineville Unit 3		236,470	2.54%		6,007
5650 Ghent Unit 1 Scrubber		138,565,707	2.54%		3,519,723
5651 Ghent Unit 1		200,261,497	2.54%		5,086,865
5652 Ghent Unit 2		124,543,857	2.54%		3,163,552
5658 Ghent Unit 2 Scrubber		67,966,248	2.54%		1,726,418
5653 Ghent Unit 3		251,295,254	2.54%		6,383,179
5660 Ghent 3 FGD		127,988,949	2.54%		3,251,062
5654 Ghent Unit 4		302,158,439	2.54%		7,675,160
5661 Ghent Unit 4 Scrubber		253,256,788	2.54%		6,433,004
0321 Trimble County Unit 2		506,708,710	2.54%		12,870,964
0322 Trimble County Unit 2 Scrubber		72,147,226	2.54%		1,832,620
	$	2,661,068,908	2.54%	$	67,594,109
314.00 Turbogenerator Units					
5603 Tyrone Unit 3	$	4,805,514	1.81%	$	86,939
5604 Tyrone Units 1&2		68,206	1.81%		1,234
5613 Green River Unit 3		4,562,207	1.81%		82,537
5614 Green River Unit 4		10,390,499	1.81%		187,979
5621 Brown Unit 1		7,512,849	1.81%		135,918
5622 Brown Unit 2		12,531,797	1.81%		226,719
5623 Brown Unit 3		29,370,580	1.81%		531,357
5651 Ghent Unit 1		36,687,332	1.81%		663,728
5652 Ghent Unit 2		30,417,603	1.81%		550,299
5653 Ghent Unit 3		42,547,917	1.81%		769,754
5654 Ghent Unit 4		57,036,984	1.81%		1,031,883
0321 Trimble County Unit 2		84,288,843	1.81%		1,524,909
	$	320,220,331	1.81%	$	5,793,256

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
315.00 Accessory Electric Equipment					
5603 Tyrone Unit 3	$	2,081,693	2.01%	$	41,917
5604 Tyrone Units 1&2		99,211	2.01%		1,998
5613 Green River Unit 3		1,205,362	2.01%		24,271
5614 Green River Unit 4		2,695,329	2.01%		54,273
5621 Brown Unit 1		3,847,279	2.01%		77,469
5622 Brown Unit 2		2,485,858	2.01%		50,055
5623 Brown Unit 3		8,761,314	2.01%		176,418
5630 Brown Unit 1,2,3 Scrubber		29,503,821	2.01%		594,091
5650 Ghent Unit 1 Scrubber		12,144,072	2.01%		244,534
5651 Ghent Unit 1		8,872,543	2.01%		178,658
5652 Ghent Unit 2		13,858,389	2.01%		279,054
5658 Ghent Unit 2 Scrubber		941,942	2.01%		18,967
5653 Ghent Unit 3		30,932,405	2.01%		622,857
5660 Ghent 3 Scrubber		12,041,998	2.01%		242,479
5654 Ghent Unit 4		24,412,797	2.01%		491,578
5661 Ghent 4 Scrubber		15,148,042	2.01%		305,022
0321 Trimble County Unit 2		42,182,158	2.01%		849,383
0322 Trimble County Unit 2 Scrubber		1,415,469	2.01%		28,502
	$	212,629,682	2.01%	$	4,281,526
316.00 Miscellaneous Plant Equipment					
5603 Tyrone Unit 3	$	553,355	1.98%	$	10,969
5604 Tyrone Units 1&2		50,127	1.98%		994
5613 Green River Unit 3		152,146	1.98%		3,016
5614 Green River Unit 4		2,408,143	1.98%		47,735
5615 Green River Units 1&2		84,750	1.98%		1,680
5621 Brown Unit 1		432,578	1.98%		8,575
5622 Brown Unit 2		106,658	1.98%		2,114
5623 Brown Unit 3		5,159,550	1.98%		102,274
5650 Ghent Unit 1 Scrubber		1,033,027	1.98%		20,477
5651 Ghent Unit 1		1,747,527	1.98%		34,640
5652 Ghent Unit 2		1,500,525	1.98%		29,744
5653 Ghent Unit 3		3,150,438	1.98%		62,449
5654 Ghent Unit 4		7,838,124	1.98%		155,370
0321 Trimble County Unit 2		3,796,552	1.98%		75,256
5591 System Laboratory		2,793,691	1.98%		55,377
	$	30,807,191	1.98%	$	610,670
317.00 Asset Retirement Obligations - Steam *		56,489,771			
Total Steam	$	3,627,150,142		$	83,801,406

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
Hydraulic Production Plant					
5691 Dix Dam					
330.10 Land Rights	$	879,311	0.00%	$	-
331.00 Structures and Improvements		616,527	1.62%		9,982
332.00 Reservoirs, Dams & Waterways		21,601,870	2.34%		505,170
333.00 Water Wheels, Turbines and Generators		4,549,436	3.43%		155,823
334.00 Accessory Electric Equipment		578,333	3.48%		20,131
335.00 Misc. Power Plant Equipment		297,024	3.09%		9,169
336.00 Roads, Railroads and Bridges		176,360	2.71%		4,775
337.00 Asset Retirement Obligations - Hydro *		57,609			-
Total Hydraulic Plant	$	28,756,470		$	705,050
Other Production Plant					
340.10 Land Rights - 5645 Brown CT 9 Gas Pipeline	$	176,409	3.27%	$	5,767
340.20 Land		118,514	0.00%		-
341.00 Structures and Improvements					
5697 Paddy's Run CT 13		1,910,328	3.27%		62,456
5635 Brown CT 5		775,082	3.27%		25,340
5636 Brown CT 6		192,814	3.27%		6,304
5637 Brown CT 7		544,966	3.27%		17,817
5638 Brown CT 8		2,012,655	3.27%		65,801
5639 Brown CT 9		4,641,055	3.27%		151,733
5640 Brown CT 10		1,865,718	3.27%		60,997
5641 Brown CT 11		1,895,014	3.27%		61,955
0470 Trimble County CT 5		3,740,231	3.27%		122,282
0471 Trimble County CT 6		3,588,684	3.27%		117,327
0474 Trimble County CT 7		3,559,155	3.27%		116,362
0475 Trimble County CT 8		3,548,852	3.27%		116,025
0476 Trimble County CT 9		3,655,976	3.27%		119,527
0477 Trimble County CT 10		3,653,030	3.27%		119,431
5696 Haefling CT 1,2,&3		434,853	3.27%		14,217
	$	36,018,413	3.27%	$	1,177,574

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

Property Group	Depreciable Plant 03/31/12	KIUC Proposed Rates ASL	KIUC Depreciation Under Proposed Rates
342.00 Fuel Holders, Producers and Accessories			
5697 Paddy's Run CT 13	$ 1,995,101	3.73%	$ 74,512
5635 Brown CT 5	795,788	3.73%	29,721
5636 Brown CT 6	406,460	3.73%	15,180
5637 Brown CT 7	405,871	3.73%	15,158
5638 Brown CT 8	252,006	3.73%	9,412
5639 Brown CT 9	2,018,754	3.73%	75,396
5640 Brown CT 10	264,131	3.73%	9,865
5641 Brown CT 11	284,823	3.73%	10,637
5645 Brown CT 9 Gas Pipeline	8,106,131	3.73%	302,744
0470 Trimble County CT 5	239,584	3.73%	8,948
0471 Trimble County CT 6	239,246	3.73%	8,935
0473 Trimble County CT Pipeline	4,850,115	3.73%	181,140
0474 Trimble County CT 7	578,059	3.73%	21,589
0475 Trimble County CT 8	576,386	3.73%	21,527
0476 Trimble County CT 9	593,786	3.73%	22,176
0477 Trimble County CT 10	622,873	3.73%	23,263
5696 Haefling CT 1,2,&3	518,705	3.73%	19,372
	$ 22,747,819	3.73%	$ 849,575
343.00 Prime Movers			
5697 Paddy's Run CT 13	$ 18,174,144	3.94%	$ 715,224
5635 Brown CT 5	14,666,936	3.94%	577,201
5636 Brown CT 6	34,600,149	3.94%	1,361,651
5637 Brown CT 7	31,657,719	3.94%	1,245,855
5638 Brown CT 8	26,710,990	3.94%	1,051,182
5639 Brown CT 9	23,335,363	3.94%	918,338
5640 Brown CT 10	20,074,766	3.94%	790,021
5641 Brown CT 11	34,794,971	3.94%	1,369,318
0470 Trimble County CT 5	32,965,168	3.94%	1,297,309
0471 Trimble County CT 6	32,853,640	3.94%	1,292,919
0474 Trimble County CT 7	23,953,735	3.94%	942,673
0475 Trimble County CT 8	23,765,360	3.94%	935,260
0476 Trimble County CT 9	23,632,815	3.94%	930,044
0477 Trimble County CT 10	23,581,342	3.94%	928,018
	$ 364,767,098	3.94%	$ 14,355,013

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
344.00 Generators					
5697 Paddy's Run CT 13	$	5,185,636	3.02%	$	156,631
5635 Brown CT 5		2,858,148	3.02%		86,330
5636 Brown CT 6		3,712,620	3.02%		112,139
5637 Brown CT 7		3,722,788	3.02%		112,446
5638 Brown CT 8		4,953,961	3.02%		149,633
5639 Brown CT 9		5,452,041	3.02%		164,678
5640 Brown CT 10		4,944,423	3.02%		149,345
5641 Brown CT 11		5,187,040	3.02%		156,673
0470 Trimble County CT 5		3,763,275	3.02%		113,669
0471 Trimble County CT 6		3,757,947	3.02%		113,508
0474 Trimble County CT 7		2,950,282	3.02%		89,113
0475 Trimble County CT 8		2,937,930	3.02%		88,740
0476 Trimble County CT 9		2,957,520	3.02%		89,331
0477 Trimble County CT 10		2,954,149	3.02%		89,229
5696 Haefling CT 1,2,&3		4,023,002	3.02%		121,514
	$	59,360,762	3.02%	$	1,792,979
345.00 Accessory Electric Equipment					
5697 Paddy's Run CT 13	$	2,456,320	3.43%	$	84,318
5635 Brown CT 5		2,479,493	3.43%		85,113
5636 Brown CT 6		1,975,216	3.43%		67,803
5637 Brown CT 7		1,935,782	3.43%		66,449
5638 Brown CT 8		2,908,499	3.43%		99,840
5639 Brown CT 9		4,205,847	3.43%		144,374
5640 Brown CT 10		2,744,493	3.43%		94,210
5641 Brown CT 11		1,987,867	3.43%		68,237
0470 Trimble County CT 5		1,737,628	3.43%		59,647
0471 Trimble County CT 6		4,324,591	3.43%		148,450
0474 Trimble County CT 7		3,148,439	3.43%		108,076
0475 Trimble County CT 8		3,139,332	3.43%		107,764
0476 Trimble County CT 9		3,234,031	3.43%		111,014
0477 Trimble County CT 10		7,196,618	3.43%		247,038
5696 Haefling CT 1,2,&3		1,333,946	3.43%		45,790
	$	44,808,102	3.43%	$	1,538,123

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
346.00 Miscellaneous Plant Equipment					
5697 Paddy's Run CT 13	$	1,089,550	3.19%	$	34,751
5635 Brown CT 5		2,139,353	3.19%		68,234
5636 Brown CT 6		53,749	3.19%		1,714
5637 Brown CT 7		35,647	3.19%		1,137
5638 Brown CT 8		291,226	3.19%		9,289
5639 Brown CT 9		760,255	3.19%		24,248
5640 Brown CT 10		274,391	3.19%		8,752
5641 Brown CT 11		590,563	3.19%		18,836
0470 Trimble County CT 5		28,964	3.19%		924
0474 Trimble County CT 7		8,889	3.19%		284
0475 Trimble County CT 8		8,861	3.19%		283
0476 Trimble County CT 9		9,114	3.19%		291
0477 Trimble County CT 10		41,869	3.19%		1,335
5696 Haefling CT 1,2,&3		35,805	3.19%		1,142
	$	5,368,236	3.19%	$	171,220
347.00 Asset Retirement Obligations Other Production *		17,791			
Total Other Production	$	533,383,144		$	19,890,251
Transmission Plant					
350.1 Land Rights	$	23,414,571	0.12%	$	28,794
350.2 Land		2,199,383	0.00%		-
352.1 Structures and Improvements-Non System Control		18,029,821	0.76%		136,324
352.2 Structures and Improvements-System Control		195,114	0.87%		1,700
353.1 Station Equipment		193,380,995	0.66%		1,268,735
353.2 System Control - Microwave Equipment		14,668,404	-0.26%		(38,001)
354 Towers & Fixtures		94,800,535	0.81%		771,954
355 Poles & Fixtures		151,316,031	1.57%		2,377,578
356 Overhead Conductors and Devices		167,790,822	1.14%		1,904,489
357 Underground Conduit		448,760	2.25%		10,110
358 Underground Conductors & Devices		1,161,549	1.52%		17,697
359 Asset Retirement Obligations - Transmission *		539,999			
Total Transmission Plant	$	667,945,984		$	6,479,380

Kentucky Utilities Company
Annualized Depreciation
as of March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
Distribution Plant					
360.1 Land Rights	$	2,039,033	0.15%	$	2,977
360.2 Land		3,271,807	0.00%		-
360.2 Land (Plant Held for Future Use)		792,599	0.00%		-
361 Structures and Improvements		7,665,070	1.31%		100,731
362 Station Equipment		145,362,874	1.96%		2,853,664
364 Poles Towers & Fixtures		297,218,364	1.60%		4,763,858
365 Overhead Conductors and Devices		283,505,700	1.60%		4,535,818
366 Underground Conduit		1,831,865	1.77%		32,443
367 Underground Conductors & Devices		142,273,183	0.97%		1,378,719
368 Line Transformers		287,943,911	1.88%		5,427,358
369 Services		89,683,318	1.24%		1,112,897
370 Meters		70,922,417	1.32%		934,930
371 Installations on Customer Premises		18,240,916	0.09%		16,087
373 Street Lighting & Signal Systems		83,014,243	2.90%		2,405,290
374 Asset Retirement Obligations - Distribution *		786,955			
Total Distribution Plant	$	1,434,552,255		$	23,564,772
General Plant					
389.2 Land	$	2,629,528	0.00%	$	-
390.1 Structures & Improvements		46,194,179	1.75%		810,405
390.2 Improvements to Leased Property		531,973	1.18%		6,276
391.1 Office Furniture & Equipment		7,806,962	4.68%		365,446
391.2 Non PC Computer Equipment		18,399,981	17.46%		3,211,806
391.31 PC Equipment		6,648,038	16.04%		1,066,075
392.10 Transportation Equipment - Cars & Light Trucks		1,865,091	1.06%		19,852
392.30 Transportation Equipment - Heavy Trucks and Other		14,104,864	0.54%		76,041
393 Stores Equipment		551,794	5.39%		29,766
394 Tool, Shop & Garage Equipment		8,221,697	3.71%		304,675
396.30 Power Operated Equipment - Large Machinery		1,188,993	6.13%		72,881
397.10 Communication Equipment - General Assets		10,171,296	8.49%		863,572
397.20 Communication Equipment - Specific Assets		20,920,746	3.78%		790,926
397.30 Communication Equipment - Fully Accrued		786,233	0.00%		-
Total General Plant	$	140,021,375		$	7,617,721
TOTAL PLANT IN SERVICE	$	6,492,013,503			
Total Annual Depreciation (excludes ARO amounts)				$	149,077,063

Less: Amounts not included in Income Statement Depreciation		
5645 Brown CT 9 Gas Pipeline	$	(308,511)
0473 Trimble County CT Pipeline		(181,140)
392.10 Transportation Equipment - Cars & Light Trucks		(19,852)
Less: ECR Depreciation		(32,438,004)
Total Annualized Depreciation Expense excluding ECR and ARO	$	116,129,556

* Represents list of ARO assets. Please note these amounts are not included in the calculation.

Kentucky Utilities Company
KIUC Adjusted Annualized ECR Depreciation

Annualized Depreciation for 2005 and 2006 ECR plans to be eliminated

	As Filed		KIUC Adjusted	
2005 ECR Plan Monthly Depreciation (from next page)	$	3,471,415	$	2,302,948
2005 Retirements Monthly Depreciation		(40,521)		(40,521)
Net 2005 ECR Plan	$	3,430,894	$	2,262,427
Months		12		12
Annualized 2005 ECR Plan	$	41,170,728	$	27,149,124
2006 ECR Plan Monthly Depreciation (from next page)	$	355,462	$	427,947
2006 Retirements Monthly Depreciation		(1,133)		(1,133)
Net 2006 ECR Plan	$	354,329	$	426,814
Months		12		12
Annualized 2006 ECR Plan		4,251,948		5,121,768
2005 and 2006 ECR Plans Total	$	45,422,676	$	32,270,892

Annualized Depreciation for all ECR plans

	As Filed		KIUC Adjusted	
2005 and 2006 ECR Plans Total (from above)	$	45,422,676	$	32,270,892
2009 ECR Plan Monthly Depreciation (from next page)	$	14,875	$	13,926
Months		12		12
Annualized 2009 ECR Plan	$	178,500	$	167,112
Annualized All ECR Plans Total		45,601,176		32,438,004

Kentucky Utilities Company
KIUC Adjusted ECR Adjustment for Proposed Rates
March 31, 2012

ECR Plan	Description	Total Installed Cost	Plant Account	Proposed Depr Rate	Proposed Monthly Depr Expense
2005	120209 - Ghent Unit 4	$ 398,915.00	312.00	2.54%	$ 844.41
2005	121597 - Ghent Unit 4	436,130.89	312.00	2.54%	923.18
2005	119961 - Brown Ash Handling Transmission Relocation	3,043,828.72	355.00	1.57%	3,985.55
2005	119961 - Brown Ash Handling Transmission Relocation	2,879,512.19	356.00	1.14%	2,723.63
2005	119961 - Brown Unit 1	1,606,687.43	312.00	2.54%	3,400.97
2005	119961 - Brown Unit 2	1,397,099.04	312.00	2.54%	2,957.32
2005	119961 - Brown Unit 2	166,696.69	315.00	2.01%	279.72
2005	119961 - Brown Unit 3	27,653,977.66	312.00	2.54%	58,536.81
2005	119961 - Brown Unit 3	691,222.10	315.00	2.01%	1,159.87
2005	118251 - Ghent Unit 3 Scrubber	127,217,232.63	312.00	2.54%	269,288.26
2005	118251 - Ghent Unit 3 Scrubber	11,993,351.47	315.00	2.01%	20,124.92
2005	118251 - Ghent Unit 3 Scrubber	69,178.00	392.10	1.06%	61.36
2005	118251 - Ghent Unit 4	7,103,212.70	311.00	1.65%	9,755.38
2005	119962 - Ghent Unit 1	25,186,670.80	312.00	2.54%	53,314.12
2005	119962 - Ghent Unit 1 Scrubber	115,281,172.63	312.00	2.54%	244,022.49
2005	119962 - Ghent Unit 1 Scrubber	9,068,617.28	315.00	2.01%	15,217.20
2005	119962 - Ghent Unit 2	28,103,907.64	312.00	2.54%	59,489.21
2005	119962 - Ghent Unit 2 Scrubber	8,916,082.79	312.00	2.54%	18,873.20
2005	119962 - Ghent Unit 2 Scrubber	938,695.80	315.00	2.01%	1,575.14
2005	120208 - Ghent Unit 2	183,430.63	312.00	2.54%	388.28
2005	120208 - Ghent Unit 4	42,504,952.57	312.00	2.54%	89,972.75
2005	120208 - Ghent Unit 4 Scrubber	134,068,516.84	312.00	2.54%	283,790.77
2005	120209 - Ghent Unit 2	179,584.08	312.00	2.54%	380.14
2005	120209 - Ghent Unit 4	14,562.76	311.00	1.65%	20.00
2005	120209 - Ghent Unit 4	3,484,937.69	312.00	2.54%	7,376.77
2005	120209 - Ghent Unit 4 Scrubber	131,082,564.27	312.00	2.54%	277,470.23
2005	120209 - Ghent Unit 4 Scrubber	425,132.40	315.00	2.01%	713.37
2005	120210 - Brown Unit 1	3,225,806.50	312.00	2.54%	6,828.26
2005	120210 - Brown Unit 1,2,3 Scrubber	43,642,101.13	311.00	1.65%	59,936.99
2005	120210 - Brown Unit 1,2,3 Scrubber	324,858,623.81	312.00	2.54%	687,647.50
2005	120210 - Brown Unit 1,2,3 Scrubber	29,318,994.37	315.00	2.01%	49,197.46
2005	120210 - Brown Unit 2	659,435.91	312.00	2.54%	1,395.87
2005	120210 - Brown Unit 3	33,196,610.45	312.00	2.54%	70,269.23
2005	126290 - Ghent Unit 3 Scrubber	227,102.80	312.00	2.54%	480.72
2005	127519 - Ghent Unit 4 Scrubber	258,547.46	312.00	2.54%	547.28
	2005 Plan Summary				**$ 2,302,948.36**
2006	121685 - Trimble County Unit 2 Scrubber	$ 737,597.72	311.00	1.65%	$ 1,013.00
2006	121685 - Trimble County Unit 2 Scrubber	179,059,507.18	312.00	2.54%	379,025.87
2006	121685 - Trimble County Unit 2 Scrubber	6,503,629.52	315.00	2.01%	10,913.13
2006	132872KU - Trimble County Unit 2 Scrubber	2,117,592.51	312.00	2.54%	4,482.43
2006	122279 - Ghent Unit 1	643,507.32	311.00	1.65%	883.78
2006	122279 - Ghent Unit 1	3,719,591.72	312.00	2.54%	7,873.48
2006	122279 - Ghent Unit 3	641,065.39	311.00	1.65%	880.42
2006	122279 - Ghent Unit 3	3,708,453.99	312.00	2.54%	7,849.90
2006	122279 - Ghent Unit 4	579,887.02	311.00	1.65%	796.40
2006	122279 - Ghent Unit 4	3,458,766.49	312.00	2.54%	7,321.38
2006	126287 - Ghent Unit 4	203,561.29	312.00	2.54%	430.89
2006	122279 - Continuing Emissions Monitoring Software	115,540.00	391.20	17.46%	1,680.67
2006	122657 - Brown Unit 3	195,935.18	312.00	2.54%	414.75
2006	122657 - Ghent Unit 1	127,777.19	312.00	2.54%	270.47
2006	122657 - Ghent Unit 3	127,777.19	312.00	2.54%	270.47
2006	122657 - Ghent Unit 4	173,056.35	312.00	2.54%	366.32
2006	122657 - Green River Unit 3	127,777.20	312.00	2.54%	270.47
2006	122657 - Green River Unit 4	145,940.85	312.00	2.54%	308.92
2006	122657 - Tyrone Unit 3	18,148.59	312.00	2.54%	38.42
2006	120404 - Brown Unit 3	46,715.34	312.00	2.54%	98.89
2006	122658 - Brown Unit 2	1,302,449.83	312.00	2.54%	2,756.97
	2006 Plan Summary				**$ 427,947.04**
2009	121682 - Trimble County Unit 2	$ 7,184,578.86	311.00	1.65%	$ 9,867.12
2009	121682 - Trimble County Unit 2	1,917,890.24	312.00	2.54%	4,059.71
	2009 Plan Summary				**$ 13,926.84**

EXHIBIT ____ (LK-22)

KIUC Adjusted Exhibit 1
Reference Schedule 1.12

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment To Reflect Annualized Depreciation Expenses
At March 31, 2012

	As Filed Electric	KIUC Electric	KIUC Adjustment
1. Annualized direct depreciation expense under proposed rates	$ 111,689,000	$ 67,790,855	
2. Annualized depreciation for 2005 and 2006 ECR plans to be eliminated	1,892,892	1,332,276	
3. Common plant allocated annualized depreciation expense (1)	12,731,875	12,731,875	
4. Total annualized depreciation expense	$ 126,313,767	$ 81,855,006	
5. Depreciation expense per books for test year	$ 127,895,417	$ 127,895,417	
6. Depreciation expense for asset retirement costs (ARO)	(2,206,653)	(2,206,653)	
7. Depreciation for environmental cost recovery (ECR) plans (2)	(71,533)	(71,533)	
8. Depreciation booked above the line for below the line items	(115)	(115)	
8. Depreciation expense per books excluding ARO and ECR	$ 125,617,116	$ 125,617,116	
9. Total Adjustment to reflect annualized depreciation expense (Line 4 - Line 8)	$ 696,651	$ (43,762,110)	$ (44,458,761)

(1) Common plant depreciation was allocated 71% to electric and 29% to gas pursuant to common utility study.
(2) Reflects the elimination of the 2005 and 2006 ECR Plans. Only reflects ECR plan amounts which will continue after effective date of new base rates in this proceeding.

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL	KIUC Depreciation Under Proposed Rates
ELECTRIC PLANT				
Intangible Plant		$ 2,240	0.00%	$ -
Steam Production Plant				
310.20	Land	$ 6,193,327	0.00%	$ -
310.25	Land	100,000	0.00%	-
311.00	Structures and Improvements			
	0112 Cane Run Unit 1	$ 4,233,240	1.50%	$ 63,392
	0121 Cane Run Unit 2	2,102,422	1.50%	31,483
	0131 Cane Run Unit 3	3,536,934	1.50%	52,965
	0141 Cane Run Unit 4	4,089,674	1.50%	61,242
	0142 Cane Run Unit 4 Scrubber	821,433	1.50%	12,301
	0151 Cane Run Unit 5	6,288,070	1.50%	94,162
	0152 Cane Run Unit 5 Scrubber	1,696,435	1.50%	25,404
	0161 Cane Run Unit 6	28,208,880	1.50%	422,421
	0162 Cane Run Unit 6 Scrubber	2,004,302	1.50%	30,014
	0211 Mill Creek Unit 1	19,884,639	1.50%	297,768
	0212 Mill Creek Unit 1 Scrubber	1,709,711	1.50%	25,603
	0221 Mill Creek Unit 2	11,486,429	1.50%	172,007
	0222 Mill Creek Unit 2 Scrubber	1,393,404	1.50%	20,866
	0231 Mill Creek Unit 3	24,500,221	1.50%	366,885
	0232 Mill Creel Unit 3 Scrubber	362,867	1.50%	5,434
	0241 Mill Creek Unit 4	64,289,491	1.50%	962,720
	0242 Mill Creek Unit 4 Scrubber	5,330,552	1.50%	79,824
	0311 Trimble County Unit 1	115,104,804	1.50%	1,723,668
	0312 Trimble County Unit 1 Scrubber	493,910	1.50%	7,396
	0321 Trimble County Unit 2	26,139,486	1.50%	391,433
		$ 323,676,904		$ 4,846,988

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

	Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
312.00	Boiler Plant Equipment					
	0103 Cane Run Locomotive	$	51,549	2.09%	$	1,080
	0104 Cane Run Rail Cars		1,501,773	2.09%		31,456
	0112 Cane Run Unit 1		1,052,271	2.09%		22,040
	0121 Cane Run Unit 2		132,276	2.09%		2,771
	0131 Cane Run Unit 3		705,480	2.09%		14,777
	0141 Cane Run Unit 4		31,384,490	2.09%		657,368
	0142 Cane Run Unit 4 Scrubber		17,050,368	2.09%		357,131
	0151 Cane Run Unit 5		40,758,450	2.09%		853,712
	0152 Cane Run Unit 5 Scrubber		28,112,261	2.09%		588,830
	0161 Cane Run Unit 6		55,736,437	2.09%		1,167,436
	0162 Cane Run Unit 6 Scrubber		32,458,665	2.09%		679,868
	0203 Mill Creek Locomotive		613,424	2.09%		12,849
	0204 Mill Creek Rail Cars		2,965,012	2.09%		62,104
	0211 Mill Creek Unit 1		56,237,501	2.09%		1,177,931
	0212 Mill Creek Unit 1 Scrubber		43,569,497	2.09%		912,591
	0221 Mill Creek Unit 2		53,553,848	2.09%		1,121,720
	0222 Mill Creek Unit 2 Scrubber		35,719,947	2.09%		748,177
	0231 Mill Creek Unit 3		146,490,839	2.09%		3,068,345
	0232 Mill Creek Unit 3 Scrubber		63,256,714	2.09%		1,324,953
	0241 Mill Creek Unit 4		246,684,529	2.09%		5,166,967
	0242 Mill Creek Unit 4 Scrubber		113,972,386	2.09%		2,387,225
	0311 Trimble County Unit 1		217,329,447	2.09%		4,552,106
	0312 Trimble County Unit 1 Scrubber		63,633,187	2.09%		1,332,838
	0321 Trimble County Unit 2		121,967,166	2.09%		2,554,681
	0322 Trimble County Unit 2 Scrubber		14,607,918	2.09%		305,972
		$	1,389,545,435		$	29,104,928
314.00	Turbogenerator Units					
	0112 Cane Run Unit 1	$	106,009	1.54%	$	1,636
	0121 Cane Run Unit 2		19,999	1.54%		309
	0131 Cane Run Unit 3		581,178	1.54%		8,971
	0141 Cane Run Unit 4		9,404,419	1.54%		145,169
	0151 Cane Run Unit 5		7,931,773	1.54%		122,437
	0161 Cane Run Unit 6		16,728,235	1.54%		258,222
	0211 Mill Creek Unit 1		14,686,468	1.54%		226,704
	0221 Mill Creek Unit 2		17,110,425	1.54%		264,121
	0231 Mill Creek Unit 3		31,564,298	1.54%		487,235
	0241 Mill Creek Unit 4		42,570,314	1.54%		657,127
	0311 Trimble County Unit 1		56,998,845	1.54%		879,850
	0321 Trimble County Unit 2		20,515,722	1.54%		316,686
		$	218,217,685		$	3,368,467

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

	Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
315.00	Accessory Electric Equipment					
	0112 Cane Run Unit 1	$	1,883,657	1.22%	$	22,960
	0121 Cane Run Unit 2		1,238,068	1.22%		15,091
	0131 Cane Run Unit 3		766,540	1.22%		9,343
	0141 Cane Run Unit 4		5,920,914	1.22%		72,171
	0142 Cane Run Unit 4 Scrubber		987,949	1.22%		12,042
	0151 Cane Run Unit 5		9,434,825	1.22%		115,003
	0152 Cane Run Unit 5 Scrubber		2,216,499	1.22%		27,017
	0161 Cane Run Unit 6		12,638,294	1.22%		154,051
	0162 Cane Run Unit 6 Scrubber		2,199,915	1.22%		26,815
	0211 Mill Creek Unit 1		15,685,072	1.22%		191,188
	0212 Mill Creek Unit 1 Scrubber		5,541,695	1.22%		67,549
	0221 Mill Creek Unit 2		7,415,271	1.22%		90,386
	0222 Mill Creek Unit 2 Scrubber		4,505,053	1.22%		54,913
	0231 Mill Creek Unit 3		15,049,880	1.22%		183,446
	0232 Mill Creel Unit 3 Scrubber		2,531,773	1.22%		30,860
	0241 Mill Creek Unit 4		24,032,541	1.22%		292,937
	0242 Mill Creek Unit 4 Scrubber		5,864,979	1.22%		71,489
	0311 Trimble County Unit 1		49,158,461	1.22%		599,202
	0312 Trimble County Unit 1 Scrubber		2,736,920	1.22%		33,361
	0321 Trimble County Unit 2		8,459,461	1.22%		103,114
		$	178,267,767		$	2,172,939
316.00	Miscellaneous Plant Equipment					
	0112 Cane Run Unit 1	$	38,746	2.90%	$	1,122
	0131 Cane Run Unit 3		11,664	2.90%		338
	0141 Cane Run Unit 4		87,249	2.90%		2,526
	0142 Cane Run Unit 4 Scrubber		6,464	2.90%		187
	0151 Cane Run Unit 5		96,972	2.90%		2,807
	0152 Cane Run Unit 5 Scrubber		47,299	2.90%		1,369
	0161 Cane Run Unit 6		2,987,196	2.90%		86,484
	0162 Cane Run Unit 6 Scrubber		31,569	2.90%		914
	0211 Mill Creek Unit 1		758,151	2.90%		21,950
	0221 Mill Creek Unit 2		125,821	2.90%		3,643
	0231 Mill Creek Unit 3		328,575	2.90%		9,513
	0241 Mill Creek Unit 4		7,331,264	2.90%		212,251
	0242 Mill Creek Unit 4 Scrubber		74,851	2.90%		2,167
	0311 Trimble County Unit 1		2,917,560	2.90%		84,468
	0321 Trimble County Unit 2		1,608,917	2.90%		46,580
		$	16,452,298		$	476,318
317.00	Asset Retirement Obligations - Steam *		27,798,267			
	Total Steam	$	2,160,251,683		$	39,969,640

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

Property Group	Depreciable Plant 03/31/12	KIUC Proposed Rates ASL	KIUC Depreciation Under Proposed Rates
Hydraulic Production Plant - Project 289			
0451 - Ohio Falls Project 289			
330.20 Land	$ 6	0.00%	$ -
331.00 Structures and Improvements	4,897,072	0.51%	24,903
332.00 Reservoirs, Dams & Waterways	11,690,252	2.05%	239,774
333.00 Water Wheels, Turbines and Generators	19,945,214	1.23%	244,660
334.00 Accessory Electric Equipment	5,509,836	2.75%	151,495
335.00 Misc. Power Plant Equipment	284,789	3.35%	9,526
336.00 Roads, Railroads and Bridges	28,797	1.54%	444
	$ 42,355,966		$ 670,802
Hydraulic Production Plant - Other Than Project 289			
0450 - Ohio Falls Other Than Project 289			
330.20 Land	$ 1	0.00%	$ -
331.00 Structures and Improvements	65,796	1.05%	693
335.00 Misc. Power Plant Equipment	25,458	3.47%	885
336.00 Roads, Railroads and Bridges	1,134	1.40%	16
337.00 Asset Retirement Obligations - Hydro *	103,529		
	$ 195,918		$ 1,594
Total Hydraulic Plant	$ 42,551,884		$ 672,396
Other Production Plant			
340.20 Land	$ 8,133	0.00%	$ -
341.00 Structures and Improvements			
0171 Cane Run GT 11	$ 211,518	3.27%	$ 6,913
0410 Zorn and River Road Gas Turbine	8,241	3.27%	269
0431 Paddys Run Generator 12	64,113	3.27%	2,095
0432 Paddys Run Generator 13	2,158,698	3.27%	70,553
0459 Brown CT 5	858,539	3.27%	28,060
0460 Brown CT 6	105,978	3.27%	3,464
0461 Brown CT 7	144,356	3.27%	4,718
0470 Trimble County CT 5	1,555,655	3.27%	50,844
0471 Trimble County CT 6	1,467,924	3.27%	47,976
0474 Trimble County CT 7	2,083,698	3.27%	68,102
0475 Trimble County CT 8	2,075,527	3.27%	67,835
0476 Trimble County CT 9	2,137,402	3.27%	69,857
0477 Trimble County CT 10	2,132,790	3.27%	69,706
	$ 15,004,439		$ 490,392

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

	Property Group	Depreciable Plant 03/31/12	KIUC Proposed Rates ASL	KIUC Depreciation Under Proposed Rates
342.00	Fuel Holders, Producers and Accessories			
	0171 Cane Run GT 11	$ 319,042	3.83%	$ 12,235
	0410 Zorn and River Road Gas Turbine	23,434	3.83%	899
	0430 Paddys Run Generator 11	9,238	3.83%	354
	0431 Paddys Run Generator 12	21,667	3.83%	831
	0432 Paddys Run Generator 13	2,255,338	3.83%	86,492
	0459 Brown CT 5	846,907	3.83%	32,479
	0460 Brown CT 6	403,060	3.83%	15,457
	0461 Brown CT 7	141,363	3.83%	5,421
	0470 Trimble County CT 5	97,997	3.83%	3,758
	0471 Trimble County CT 6	97,862	3.83%	3,753
	0473 Trimble County CT Pipeline	1,998,391	3.83%	76,638
	0474 Trimble County CT 7	338,423	3.83%	12,978
	0475 Trimble County CT 8	337,096	3.83%	12,928
	0476 Trimble County CT 9	347,147	3.83%	13,313
	0477 Trimble County CT 10	361,860	3.83%	13,877
		$ 7,598,825		$ 291,413
343.00	Prime Movers			
	0432 Paddys Run Generator 13	$ 20,575,461	3.80%	$ 780,986
	0459 Brown CT 5	15,877,891	3.80%	602,679
	0460 Brown CT 6	19,951,722	3.80%	757,310
	0461 Brown CT 7	18,239,647	3.80%	692,325
	0470 Trimble County CT 5	13,538,630	3.80%	513,888
	0471 Trimble County CT 6	13,456,801	3.80%	510,782
	0474 Trimble County CT 7	14,040,786	3.80%	532,948
	0475 Trimble County CT 8	13,925,742	3.80%	528,581
	0476 Trimble County CT 9	13,836,332	3.80%	525,188
	0477 Trimble County CT 10	13,781,724	3.80%	523,115
		$ 157,224,736		$ 5,967,802
344.00	Generators			
	0171 Cane Run GT 11	$ 2,910,124	3.01%	$ 87,723
	0410 Zorn and River Road Gas Turbine	1,827,581	3.01%	55,090
	0430 Paddys Run Generator 11	1,523,116	3.01%	45,913
	0431 Paddys Run Generator 12	2,991,589	3.01%	90,178
	0432 Paddys Run Generator 13	5,859,858	3.01%	176,639
	0459 Brown CT 5	3,249,360	3.01%	97,948
	0460 Brown CT 6	2,417,995	3.01%	72,888
	0461 Brown CT 7	2,421,079	3.01%	72,981
	0470 Trimble County CT 5	1,539,295	3.01%	46,400
	0471 Trimble County CT 6	1,537,168	3.01%	46,336
	0474 Trimble County CT 7	1,726,824	3.01%	52,053
	0475 Trimble County CT 8	1,717,277	3.01%	51,765
	0476 Trimble County CT 9	1,728,008	3.01%	52,089
	0477 Trimble County CT 10	1,722,674	3.01%	51,928
		$ 33,171,948		$ 999,931

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

	Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
345.00	Accessory Electric Equipment					
	0171 Cane Run GT 11	$	116,627	3.37%	$	3,925
	0410 Zorn and River Road Gas Turbine		44,283	3.37%		1,490
	0430 Paddys Run Generator 11		68,109	3.37%		2,292
	0431 Paddys Run Generator 12		912,642	3.37%		30,712
	0432 Paddys Run Generator 13		2,778,993	3.37%		93,518
	0459 Brown CT 5		2,742,563	3.37%		92,292
	0460 Brown CT 6		970,189	3.37%		32,648
	0461 Brown CT 7		953,200	3.37%		32,077
	0470 Trimble County CT 5		706,963	3.37%		23,790
	0471 Trimble County CT 6		1,594,892	3.37%		53,671
	0474 Trimble County CT 7		1,843,364	3.37%		62,032
	0475 Trimble County CT 8		1,836,141	3.37%		61,789
	0476 Trimble County CT 9		1,890,840	3.37%		63,630
	0477 Trimble County CT 10		4,387,836	3.37%		147,658
		$	20,846,642		$	701,524
346.00	Miscellaneous Plant Equipment					
	0410 Zorn and River Road Gas Turbine	$	9,488	3.36%	$	319
	0430 Paddys Run Generator 11		9,494	3.36%		319
	0432 Paddys Run Generator 13		1,281,034	3.36%		43,077
	0459 Brown CT 5		2,395,225	3.36%		80,544
	0460 Brown CT 6		22,456	3.36%		755
	0461 Brown CT 7		23,048	3.36%		775
	0470 Trimble County CT 5		14,529	3.36%		489
	0474 Trimble County CT 7		5,205	3.36%		175
	0475 Trimble County CT 8		5,183	3.36%		174
	0476 Trimble County CT 9		5,328	3.36%		179
	0477 Trimble County CT 10		25,333	3.36%		852
		$	3,796,323		$	127,658
347.00	Asset Retirement Obligations Other Production *		38,429			
	Total Other Production	$	237,689,475		$	8,578,720

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
Electric Transmission Plant					
350.2 Transmission Lines Land	$	1,573,049	0.00%	$	-
350.1 Land Rights		7,791,511	0.26%		20,258
352.1 Structures & Improvements		6,471,400	1.68%		108,720
353.1 Station Equipment		127,692,585	0.79%		1,008,771
354 Towers & Fixtures		43,126,250	0.40%		172,505
355 Poles & Fixtures		53,760,275	1.56%		838,660
356 Overhead Conductors & Devices		47,544,070	0.47%		223,457
357 Underground Conduit		2,278,628	0.35%		7,975
358 Underground Conductors & Devices		7,425,284	2.10%		155,931
359 Asset Retirement Obligations - Transmission *		252,454			
Total Transmission Plant	$	297,915,506		$	2,536,277
Electric Distribution Plant					
360.2 Substation Land	$	5,348,665	0.00%	$	-
360.2 Substation Land Class A (Plant Held Future Use)		627,088	0.00%		-
361 Substation Structures		4,888,254	0.78%		38,128
362.1 Substation Equipment		114,763,926	1.57%		1,801,794
364 Poles Towers & Fixtures		140,371,136	1.77%		2,484,569
365 Overhead Conductors &Devices		241,550,956	1.77%		4,275,452
366 Underground Conduit		69,033,771	1.03%		711,048
367 Underground Conductors & Devices		149,365,140	1.09%		1,628,080
368 Line Transformers		140,986,634	2.13%		3,003,015
369.1 Underground Services		6,064,961	2.27%		137,675
369.2 Overhead Services		22,341,688	1.12%		250,227
370 Meters		38,125,261	0.92%		350,752
373.1 Overhead Street Lighting		35,629,640	4.07%		1,450,126
373.2 Underground Street Lighting		48,916,028	2.76%		1,350,082
374 Asset Retirement Obligations - Distribution *		626,515			
Total Distribution Plant	$	1,018,639,663		$	17,480,948

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
Electric General Plant					
392.1 Transportation Equipment - Cars & Light Trucks	$	1,570,998	2.22%	$	34,876
392.2 Transportation Equipment Trailers		682,934	3.03%		20,693
392.3 Transportation Equipment - Heavy Trucks and Other		6,692,703	2.23%		149,247
394 Tools, Shop, and Garage Equipment		4,652,755	4.27%		198,673
396.1 Power Operated Equipment - Small Machinery		1,292,580	0.00%		-
396.2 Power Operated Equipment - Other		151,087	3.69%		5,575
396.3 Power Operated Equipment - Large Machinery		1,110,685	2.65%		29,433
Total General Plant	$	16,153,742		$	438,497
TOTAL ELECTRIC PLANT	$	3,773,204,193		$	69,676,478
Less: Amounts not included in Income Statement Depreciation					
0103 Cane Run Locomotive				$	(1,080)
0104 Cane Run Rail Cars					(31,456)
0203 Mill Creek Locomotive					(12,849)
0204 Mill Creek Rail Cars					(62,104)
0473 Trimble County CT Pipeline					(76,638)
392.1 Transportation Equipment - Cars & Light Trucks					(34,876)
392.3 Transportation Equipment - Heavy Trucks and Other					(149,247)
396.1 Power Operated Equipment - Small Machinery					-
396.3 Power Operated Equipment - Large Machinery					(29,433)
Less: ECR Depreciation					(1,487,940)
Total Annualized Depreciation Expense excluding ECR and ARO				$	67,790,855

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
GAS PLANT					
Intangible Plant	$	387	10.58%	$	41
Underground Storage					
350.1 Land	$	32,864	0.00%	$	-
350.2 Rights of Way		95,614	0.56%		535
351.2 Compressor Station Structures		5,426,010	2.01%		109,063
351.3 Reg Station Structures		33,152	1.14%		378
351.4 Other Structures		2,652,176	1.82%		48,270
352.40 Well Drilling		2,724,714	0.72%		19,618
352.50 Well Equipment ARO		5,793,188	2.70%		156,416
352.55 Well Equipment		7,475,494	2.70%		201,838
352.1 Storage Leaseholds & Rights		548,241	0.00%		-
352.2 Reservoirs		400,511	0.00%		-
352.3 Nonrecoverable Natural Gas		9,648,855	0.83%		80,085
Gas Stored Underground Non-Current		2,139,990	0.00%		-
353 Lines		15,285,580	1.82%		278,198
354 Compressor Station Equipment		17,056,348	2.37%		404,235
355 Measuring & Regulating Equipment		524,850	1.53%		8,030
356 Purification Equipment		13,340,431	1.97%		262,806
357 Other Equipment		1,719,439	2.25%		38,687
358 Asset Retirement Obligations - Und Storage *		5,201,173			
Total Underground Storage	$	90,098,630		$	1,608,159
Gas Transmission Plant					
365.2 Rights of Way	$	220,659	0.16%	$	353
367 Mains		18,939,475	0.79%		149,622
368.07 Asset Retirement Obligation - Cost Gas Trans		3,941,519			
Total Transmission Plant	$	23,101,653		$	149,975

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

Property Group		Depreciable Plant 03/31/12	KIUC Proposed Rates ASL		KIUC Depreciation Under Proposed Rates
Gas Distribution Plant					
374 Land	$	59,725	0.00%	$	-
374.2 Land Rights		74,018	0.00%		-
375.1 City Gate Structures		367,966	1.46%		5,372
375.2 Other Distribution Structures		532,497	5.26%		28,009
376 Mains		336,076,717	1.89%		6,351,850
378 Measuring and Reg Equipment		12,466,709	2.58%		321,641
379 Meas & Reg Equipment - City Gate		4,460,808	2.12%		94,569
380 Services		195,651,821	3.79%		7,415,204
381 Meters		39,990,525	4.03%		1,611,618
383 House Regulators		23,914,706	4.10%		980,503
385 Industrial Meas & Reg Station Equip		944,360	2.85%		26,914
387 Other Equipment		51,112	2.78%		1,421
388 Asset Retirement Obligations - Distribution *		11,931,609			
Total Distribution Plant	$	626,522,573		$	16,837,101
Gas General Plant					
392.1 Transportation Equipment - Cars & Light Trucks	$	250,262	2.63%	$	6,582
392.2 Trailers		599,856	4.80%		28,793
392.3 Transportation Equipment - Heavy Trucks and Other		1,131,842	1.75%		19,807
394 Other Equipment		4,533,726	4.66%		211,272
396.1 Power Operated Equipment - Small Machinery		105,665	0.00%		-
396.2 Power Operated Equipment - Other		177,782	5.90%		10,489
396.3 Power Operated Equipment - Large Machinery		2,181,087	1.16%		25,301
Total General Plant	$	8,980,220		$	302,244
TOTAL GAS PLANT	$	748,703,463		$	18,897,520

Less: Amounts not included in Income Statement Depreciation		
392.1 Transportation Equipment - Cars & Light Trucks	$	(6,582)
392.3 Transportation Equipment - Heavy Trucks and Other		(19,807)
396.1 Power Operated Equipment - Small Machinery		-
396.3 Power Operated Equipment - Large Machinery		(25,301)
Total Annualized Depreciation Expense excluding ECR and ARO	$	18,845,830

Louisville Gas and Electric Company
Annualized Depreciation
at March 31, 2012

Property Group	Depreciable Plant 03/31/12	KIUC Proposed Rates ASL	KIUC Depreciation Under Proposed Rates
COMMON UTILITY PLANT			
Intangible Plant			
301 Organization	$ 83,782	0.00%	$ -
303 Misc. Intangible Plant - Software	21,873,636	13.97%	3,055,747
303.1 CCS Software	44,513,680	9.92%	4,415,757
Total Intangible Plant	$ 66,471,098		$ 7,471,504
Common General Plant			
389.1 Land	$ 1,685,316	0.00%	$ -
389.2 Land Rights	202,095	0.00%	-
390.10 Structures and Improvements	61,433,240	3.40%	2,088,730
390.20 Structures and Improvements - Transportation	412,151	5.98%	24,647
390.30 Structures and Improvements - Stores	10,750,498	1.96%	210,710
390.40 Structures and Improvements - Shops	536,692	2.05%	11,002
390.60 Structures and Improvements - Microwave	1,078,816	2.30%	24,813
391.10 Office Furniture	8,673,967	19.94%	1,729,589
391.20 Office Equipment	2,086,580	8.16%	170,265
391.30 Computer Equipment - Non PC	14,508,118	3.43%	497,628
391.31 Personal Computers	4,136,708	21.88%	905,112
391.40 Security Equipment	2,241,823	18.18%	407,563
392.1 Transportation Equipment - Cars & Light Trucks	179,513	11.38%	20,429
392.2 Transportation Equipment - Trailers	83,874	6.34%	5,318
392.3 Transportation Equipment - Heavy Trucks and Other	65,584	0.00%	-
393 Stores Equipment	1,135,864	5.82%	66,107
394 Other Equipment	3,624,119	5.04%	182,656
396.2 Power Operated Equipment - Other	14,147	6.57%	929
396.3 Power Operated Equipment - Large Machinery	235,831	1.13%	2,665
397.10 Communications Equipment - General Assets	29,003,600	13.14%	3,811,073
397.20 Communications Equipment - Specific Assets	5,292,033	4.89%	258,780
397.30 Communications Equipment - Fully Accrued Assets	11,378,217	0.00%	-
397.40 Communications Equipment - Transfer to Meter Equipment	2,243,315	2.84%	63,710
397.50 Communications Equipment - Transfer to Structure Account	77,123	2.70%	2,082
398.00 Miscellaneous Equipment	17,206	0.00%	-
399.10 ARO Asset Retirement Obligations - Common *	101,390		
Total General Plant	$ 161,197,820		$ 10,483,808
TOTAL COMMON UTILITY PLANT	**$ 227,668,918**		**$ 17,955,312**

Less: Amounts not Included in Income Statement Depreciation	
392.1 Transportation Equipment - Cars & Light Trucks	$ (20,429)
392.3 Transportation Equipment - Heavy Trucks and Other	-
396.3 Power Operated Equipment - Large Machinery	(2,665)
Total Annualized Depreciation Expense excluding ECR and ARO	**$ 17,932,218**
Electric Allocation of Common Depreciation Expense (71%)	**$ 12,731,875**
Gas Allocation of Common Depreciation Expense (29%)	**$ 5,200,343**

TOTAL PLANT IN SERVICE **$ 4,749,576,574**

* Represents list of ARO assets. Please note these amounts are not included in the calculation.

Louisville Gas and Electric Company
KIUC Adjusted Annualized ECR Depreciation

Annualized Depreciation for 2005 and 2006 ECR plans to be eliminated

	As Filed	KIUC Adjusted
2005 ECR Plan Monthly Depreciation (from next page)	$ 54,143	$ 30,137
2005 Retirements Monthly Depreciation	(5,253)	(5,253)
Net 2005 ECR Plan	$ 48,890	$ 24,884
Months	12	12
Annualized 2005 ECR Plan	$ 586,680	$ 298,608
2006 ECR Plan Monthly Depreciation (from next page)	$ 108,851	$ 86,139
Months	12	12
Annualized 2006 ECR Plan	$ 1,306,212	$ 1,033,668
2005 and 2006 ECR Plans Total	$ 1,892,892	$ 1,332,276

Annualized Depreciation for all ECR plans

	As Filed	KIUC Adjusted
2005 and 2006 ECR Plans Total (from above)	$ 1,892,892	$ 1,332,276
2009 ECR Plan Monthly Depreciation (from next page)	$ 18,066	$ 12,972
Months	12	12
Annualized 2009 ECR Plan	$ 216,792	$ 155,664
Annualized All ECR Plans Total	$ 2,109,684	$ 1,487,940

Louisville Gas and Electric Company
KIUC Adjusted ECR Adjustment for New Rates
March 31, 2012

ECR Plan	Description	Total Installed Cost	Plant Account	Proposed Depr Rate	Proposed Monthly Depr Expense
2005	112767 - Mill Creek Unit 4	100,000.00	310.20	0.0000	-
2005	112767 - Mill Creek Unit 4	3,036,367.19	311.00	1.50%	3,789.07
2005	112767 - Mill Creek Unit 4	1,587,131.44	312.00	2.09%	2,770.29
2005	112767 - Mill Creek Unit 4 Scrubber	94,931.00	312.00	2.09%	165.70
2005	117136 - Cane Run Unit 6	2,462,471.50	311.00	1.50%	3,072.91
2005	117136 - Cane Run Unit 6	144,456.80	312.00	2.09%	252.15
2005	117136 - Cane Run Unit 6 Scrubber	2,988,137.00	312.00	2.09%	5,215.71
2005	121587 - Trimble County Unit 1 Scrubber	850,100.28	312.00	2.09%	1,483.83
2005	122151 - Cane Run Unit 6 Scrubber	308,507.28	312.00	2.09%	538.49
2005	119943 - Trimble County Unit 1 Scrubber	7,361,077.48	312.00	2.09%	12,848.54
	Total 2005 Plan				**30,136.69**
2006	121684 - Trimble County Unit 2 Scrubber	176,605.50	311.00	1.50%	220.39
2006	121684 - Trimble County Unit 2 Scrubber	42,033,278.49	312.00	2.09%	73,367.85
2006	121684 - Trimble County Unit 2 Scrubber	1,529,926.61	315.00	1.22%	1,554.05
2006	132872 - Trimble County Unit 2 Scrubber	496,613.07	312.00	2.09%	866.82
2006	122280 - Trimble County Unit 1	468,282.66	311.00	1.50%	584.37
2006	122280 - Trimble County Unit 1	2,971,793.70	312.00	2.09%	5,187.18
2006	121176 - Cane Run Unit 6	27,584.00	312.00	2.09%	48.15
2006	121176 - Mill Creek Unit 4	38,545.00	312.00	2.09%	67.28
2006	121176 - Trimble County Unit 1	20,073.00	312.00	2.09%	35.04
2006	121955 - Monitoring System Software	77,639.00	391.30	3.43%	221.92
2006	122656 - Cane Run Unit 4	172,485.23	312.00	2.09%	301.07
2006	122656 - Cane Run Unit 5	172,485.23	312.00	2.09%	301.07
2006	122656 - Cane Run Unit 6	172,485.23	312.00	2.09%	301.07
2006	122656 - Mill Creek Unit 1	299,141.12	312.00	2.09%	522.14
2006	122656 - Mill Creek Unit 2	299,141.13	312.00	2.09%	522.14
2006	122656 - Mill Creek Unit 3	299,141.13	312.00	2.09%	522.14
2006	122656 - Mill Creek Unit 4	299,141.13	312.00	2.09%	522.14
2006	122656 - Trimble County Unit 1	172,485.23	312.00	2.09%	301.07
2006	115814 - Mill Creek Unit 1	72,995.00	312.00	2.09%	127.41
2006	115815 - Mill Creek Unit 2	86,735.00	312.00	2.09%	151.39
2006	115816 - Mill Creek Unit 3	87,746.00	312.00	2.09%	153.16
2006	115817 - Mill Creek Unit 4	149,675.00	312.00	2.09%	261.25
	Total 2006 plan				**86,139.10**
2009	121683 - Trimble County Unit 2 Scrubber	7,586,250.26	311.00	1.50%	9,466.86
2009	121683 - Trimble County Unit 2 Scrubber	2,008,096.85	312.00	2.09%	3,505.07
	Total 2009 Plan				**12,971.93**

EXHIBIT ____ (LK-23)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-15

Responding Witness: Daniel K. Arbough

Q1-15. Please provide a five year monthly history from January 2007 through the most recent month available (2007-2012) of the average daily balances of short term debt by type of short term debt security and/or source (bank loans, commercial paper, money pool, receivables financing, etc.), the average interest rate for each month by type of short term debt and/or source, and the basis for the interest rate for each month by type of short term debt and/or source, e.g., LIBOR + 1%.

A1-15. Attached is a five year monthly history (2007-2012) of the average daily balances of short-term debt. During this period Kentucky Utilities Company's (KU) short-term debt has been sourced through a Money Pool agreement. Effective December 1, 2011, the daily outstanding balance of all Money Pool loans during a calendar month accrue interest at the rates for A2/P2/F2 rated US Commercial Paper programs as quoted by Bloomberg under the ticker DCPD030D on the last business day of the prior calendar month. Prior to December 1, 2011, the daily outstanding balance of all short term loans accrued interest at the rate for high-grade unsecured 30-day commercial paper of major corporations sold through dealers as quoted in The Wall Street Journal (the "Average Composite") on the last business day of the prior calendar month.

KU entered into a $400 million syndicated credit facility on November 1, 2010. Under the facility, KU has the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings generally bear interest at LIBOR-based rates plus a spread, depending upon the company's senior unsecured long-term debt rating. No borrowings have occurred under the facility.

In February 2012, KU established a commercial paper program for up to $250 million to provide an additional financing source to fund its short-term liquidity needs. Commercial paper issuances will be supported by KU's syndicated credit facilities. On April 18, 2012, KU issued $1,000,000 overnight at a rate of .41% as a test trade. Interest for issuances are based on market rates determined by the commercial paper dealer. No other commercial paper borrowings have occurred during 2012.

KU - Money Pool Borrowings

Month/Year	Average Daily Balance	Average Interest Rate
January-07	$76,576,024.59	5.270%
February-07	$67,629,674.69	5.260%
March-07	$66,906,116.50	5.260%
April-07	$34,358,505.61	5.260%
May-07	$89,762,741.50	5.260%
June-07	$126,776,634.65	5.260%
July-07	$149,287,272.75	5.280%
August-07	$193,959,429.00	5.240%
September-07	$169,563,279.81	5.620%
October-07	$85,925,304.00	5.050%
November-07	$57,195,247.55	4.720%
December-07	$73,478,760.25	4.750%
January-08	$26,481,204.00	4.980%
February-08	$34,988,292.71	3.080%
March-08	$43,500,047.75	3.080%
April-08	$51,952,034.65	2.630%
May-08	$79,860,329.00	2.840%
June-08	$73,191,389.48	2.430%
July-08	$102,288,454.00	2.450%
August-08	$132,249,735.25	2.440%
September-08	$114,129,099.16	2.450%
October-08	$97,178,922.75	4.950%
November-08	$118,573,099.16	2.950%
December-08	$83,309,297.75	1.490%
January-09	$14,894,563.38	0.5400%
February-09	$13,612,087.33	0.7900%
March-09	$16,073,469.15	0.7500%
April-09	$27,064,244.32	0.5500%
May-09	$53,960,235.25	0.4000%
June-09	$80,707,212.06	0.3000%
July-09	$39,338,391.50	0.3500%
August-09	$0.00	0.3000%
September-09	$0.00	0.2500%
October-09	$5,872,891.50	0.2200%
November-09	$8,062,566.90	0.2200%
December-09	$8,815,654.00	0.2000%
January-10	$51,871,797.75	0.2000%
February-10	$52,730,264.34	0.2000%
March-10	$38,074,954.00	0.2100%
April-10	$17,071,308.84	0.2100%
May-10	$50,661,454.00	0.2300%
June-10	$68,316,179.81	0.3400%
July-10	$74,533,204.00	0.3500%
August-10	$63,809,922.75	0.2800%

Month/Year	Average Daily Balance	Average Interest Rate
September-10	$27,766,502.39	0.2800%
October-10	$41,761,105.52	0.2500%
November-10	$51,247,722.06	0.2500%
December-10	$3,593,312.50	0.2500%
January-11	$10,781,562.50	0.2500%
February-11	$5,689,379.31	0.2500%
March-11	$0.00	0.2500%
April-11	$0.00	0.2000%
May-11	$0.00	0.1900%
June-11	$0.00	0.1600%
July-11	$0.00	0.1600%
August-11	$0.00	0.1200%
September-11	$0.00	0.1700%
October-11	$0.00	0.1700%
November-11	$0.00	0.1300%
December-11	$0.00	0.4500%
January-12	$0.00	0.5000%
February-12	$0.00	0.4300%
March-12	$0.00	0.4100%
April-12	$0.00	0.4200%
May-12	$0.00	0.3900%
June-12	$691,800.00	0.4800%

KU - Commercial Paper Borrowings

Month/Year	Average Daily Balance	Average Interest Rate
April-12	$33,333.00	0.4100%
May-12	$0.00	0.0000%
June-12	$0.00	0.0000%

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

**Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012**

Question No. 1-14

Responding Witness: Daniel K. Arbough

Q1-14. Please provide a five year monthly history from January 2007 through the most recent month available (2007-2012) of the average daily balances of short term debt by type of short term debt security and/or source (bank loans, commercial paper, money pool, receivables financing, etc.), the average interest rate for each month by type of short term debt and/or source, and the basis for the interest rate for each month by type of short term debt and/or source, e.g., LIBOR + 1%.

A1-14. Attached is a five year monthly history (2007-2012) of the average daily balances of short-term debt. During this period Louisville Gas and Electric Company's (LG&E) short-term debt has been primarily sourced through a Money Pool agreement. Effective December 1, 2011, the daily outstanding balance of all Money Pool loans during a calendar month accrue interest at the rates for A2/P2/F2 rated US Commercial Paper programs as quoted by Bloomberg under the ticker DCPD030D on the last business day of the prior calendar month. Prior to December 1, 2011, the daily outstanding balance of all short term loans accrued interest at the rate for high-grade unsecured 30-day commercial paper of major corporations sold through dealers as quoted in The Wall Street Journal (the "Average Composite") on the last business day of the prior calendar month.

LG&E entered into a $400 million syndicated credit facility on November 1, 2010. Under the facility, LG&E has the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings generally bear interest at LIBOR-based rates plus a spread, depending upon the company's senior unsecured long-term debt rating. At the time of the borrowing the spread was 2.00%. Attached is a monthly history (2010-2012) of the average daily balances of short term debt borrowed under the facility.

In February 2012, LG&E established a commercial paper program for up to $250 million to provide an additional financing source to fund its short-term liquidity needs. Commercial paper issuances will be supported by LG&E's syndicated credit facility. On April 18, 2012, LG&E issued $1,000,000 overnight at a rate of

.41% as a test trade. Interest for issuances are based on market rates determined by the commercial paper dealer. No other commercial paper borrowings have occurred during 2012.

LGE - Money Pool Borrowings

Month/Year	Average Daily Balance	Average Interest Rate
January-07	$54,965,454.55	5.270%
February-07	$60,032,482.76	5.260%
March-07	$17,797,593.75	5.260%
April-07	$7,963,903.23	5.260%
May-07	$20,492,218.75	5.260%
June-07	$42,097,000.00	5.260%
July-07	$79,112,750.00	5.280%
August-07	$82,031,156.25	5.240%
September-07	$76,146,580.65	5.620%
October-07	$91,862,437.50	5.050%
November-07	$100,511,774.19	4.720%
December-07	$71,306,306.25	4.750%
January-08	$62,527,887.50	4.980%
February-08	$42,261,909.68	3.080%
March-08	$38,754,262.50	3.080%
April-08	$138,886,262.50	2.630%
May-08	$160,865,606.25	2.840%
June-08	$172,720,941.94	2.430%
July-08	$266,829,512.50	2.450%
August-08	$308,515,950.00	2.440%
September-08	$320,625,264.52	2.450%
October-08	$330,075,012.50	4.950%
November-08	$324,371,458.06	2.950%
December-08	$220,673,387.50	1.490%
January-09	$203,853,681.25	0.5400%
February-09	$158,085,779.31	0.7900%
March-09	$115,697,806.25	0.7500%
April-09	$122,559,077.42	0.5500%
May-09	$115,686,212.50	0.4000%
June-09	$103,614,754.84	0.3000%
July-09	$147,595,931.25	0.3500%
August-09	$155,036,462.50	0.3000%
September-09	$143,386,270.97	0.2500%
October-09	$143,327,993.75	0.2200%
November-09	$144,216,980.65	0.2200%
December-09	$157,782,806.25	0.2000%
January-10	$155,928,837.50	0.2000%
February-10	$105,716,055.17	0.2000%
March-10	$101,566,712.50	0.2100%
April-10	$113,789,787.10	0.2100%
May-10	$124,102,962.50	0.2300%
June-10	$133,668,400.00	0.3400%
July-10	$127,787,306.25	0.3500%

Month/Year	Average Daily Balance	Average Interest Rate
August-10	$117,964,493.75	0.2800%
September-10	$97,692,012.90	0.2800%
October-10	$114,602,275.00	0.2500%
November-10	$10,697,813.19	0.2500%
December-10	$2,917,468.75	0.2500%
January-11	$21,147,781.25	0.2500%
February-11	$16,560,793.10	0.2500%
March-11	$437,250.00	0.2500%
April-11	$0.00	0.2000%
May-11	$0.00	0.1900%
June-11	$0.00	0.1600%
July-11	$0.00	0.1600%
August-11	$0.00	0.1200%
September-11	$0.00	0.1700%
October-11	$0.00	0.1700%
November-11	$0.00	0.1300%
December-11	$0.00	0.4500%
January-12	$0.00	0.5000%
February-12	$0.00	0.4300%
March-12	$0.00	0.4100%
April-12	$0.00	0.4200%
May-12	$0.00	0.3900%
June-12	$0.00	0.4800%

LGE - Syndicated Credit Facility

Month/Year	Average Daily Balance	Average Interest Rate
November-10	$146,700,000.00	2.2600%
December-10	$163,000,000.00	2.2680%
January-11	$94,645,161.29	2.2700%
February-11	$0.00	0.0000%
March-11	$0.00	0.0000%
April-11	$0.00	0.0000%
May-11	$0.00	0.0000%
June-11	$0.00	0.0000%
July-11	$0.00	0.0000%
August-11	$0.00	0.0000%
September-11	$0.00	0.0000%
October-11	$0.00	0.0000%
November-11	$0.00	0.0000%
December-11	$0.00	0.0000%
January-12	$0.00	0.0000%
February-12	$0.00	0.0000%
March-12	$0.00	0.0000%
April-12	$0.00	0.0000%
May-12	$0.00	0.0000%
June-12	$0.00	0.0000%

LGE - Commercial Paper Borrowings

Month/Year	Average Daily Balance	Average Interest Rate
April-12	$33,333.00	0.4100%
May-12	$0.00	0.0000%
June-12	$0.00	0.0000%

EXHIBIT ____ (LK-24)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated August 28, 2012

Question No. 2.26

Responding Witness: Daniel K. Arbough

Q2.26 Refer to the Company's response to KIUC 1-35 and the fact that the Company had "cash remaining" after it financed to take advantage of low market interest rates. Please provide the daily amounts of amount of cash and short term investments at December 31, 2011 through the most recent date for which actual data is available.

A2.26 Attached are the daily amounts of cash and short-term investments at December 31, 2011 through August 29, 2012. The total daily cash and short term investment balances exclude the service center customer overnight deposit balances at small banks throughout the state as these daily balance amounts are not significant or available.

	Cash and Short Term Investments	
12/31/2011	$	32,974,632.25
1/1/2012	$	32,974,632.25
1/2/2012	$	32,974,632.25
1/3/2012	$	32,051,831.80
1/4/2012	$	38,714,543.13
1/5/2012	$	43,607,716.87
1/6/2012	$	40,881,878.02
1/7/2012	$	40,881,878.02
1/8/2012	$	40,881,878.02
1/9/2012	$	43,404,004.10
1/10/2012	$	48,425,360.39
1/11/2012	$	53,175,139.93
1/12/2012	$	23,224,145.76
1/13/2012	$	10,509,037.77
1/14/2012	$	10,509,037.77
1/15/2012	$	10,509,037.77
1/16/2012	$	10,509,037.77
1/17/2012	$	3,123,934.56
1/18/2012	$	9,297,102.94
1/19/2012	$	14,755,880.65
1/20/2012	$	11,243,012.64
1/21/2012	$	11,243,012.64
1/22/2012	$	11,243,012.64
1/23/2012	$	18,248,178.02
1/24/2012	$	23,164,081.86
1/25/2012	$	12,479,639.88
1/26/2012	$	15,863,752.10
1/27/2012	$	19,012,323.20
1/28/2012	$	19,012,323.20
1/29/2012	$	19,012,323.20
1/30/2012	$	21,651,446.98
1/31/2012	$	29,709,830.87
2/1/2012	$	32,437,794.20
2/2/2012	$	14,344,516.42
2/3/2012	$	17,742,821.50
2/4/2012	$	17,742,821.50
2/5/2012	$	17,742,821.50
2/6/2012	$	20,874,252.14
2/7/2012	$	26,608,911.74
2/8/2012	$	35,186,820.68
2/9/2012	$	40,785,939.86
2/10/2012	$	44,138,009.84
2/11/2012	$	44,138,009.84

Cash and Short Term Investments		
2/12/2012	$	44,138,009.84
2/13/2012	$	48,424,804.02
2/14/2012	$	54,350,446.95
2/15/2012	$	50,011,693.74
2/16/2012	$	61,082,837.09
2/17/2012	$	62,121,110.39
2/18/2012	$	62,121,110.39
2/19/2012	$	62,121,110.39
2/20/2012	$	62,121,110.39
2/21/2012	$	35,419,088.20
2/22/2012	$	46,987,974.95
2/23/2012	$	50,596,002.84
2/24/2012	$	54,442,276.91
2/25/2012	$	54,442,276.91
2/26/2012	$	54,442,276.91
2/27/2012	$	38,263,393.72
2/28/2012	$	45,216,060.85
2/29/2012	$	49,629,239.84
3/1/2012	$	53,191,883.60
3/2/2012	$	50,188,659.92
3/3/2012	$	50,188,659.92
3/4/2012	$	50,188,659.92
3/5/2012	$	52,237,148.06
3/6/2012	$	57,264,711.26
3/7/2012	$	64,705,957.39
3/8/2012	$	55,885,309.24
3/9/2012	$	54,978,093.23
3/10/2012	$	54,978,093.23
3/11/2012	$	54,978,093.23
3/12/2012	$	53,960,011.02
3/13/2012	$	60,405,550.31
3/14/2012	$	68,902,785.46
3/15/2012	$	62,814,260.91
3/16/2012	$	65,641,761.14
3/17/2012	$	65,641,761.14
3/18/2012	$	65,641,761.14
3/19/2012	$	52,407,993.57
3/20/2012	$	58,830,325.63
3/21/2012	$	62,119,999.50
3/22/2012	$	69,961,065.13
3/23/2012	$	72,899,616.39
3/24/2012	$	72,899,616.39
3/25/2012	$	72,899,616.39
3/26/2012	$	64,616,239.22

	Cash and Short Term Investments	
3/27/2012	$	66,685,087.46
3/28/2012	$	71,323,566.45
3/29/2012	$	49,345,357.06
3/30/2012	$	50,645,502.02
3/31/2012	$	50,645,502.02
4/1/2012	$	50,645,502.02
4/2/2012	$	46,171,796.73
4/3/2012	$	52,753,838.38
4/4/2012	$	55,219,143.58
4/5/2012	$	57,822,438.02
4/6/2012	$	61,311,314.88
4/7/2012	$	61,311,314.88
4/8/2012	$	61,311,314.88
4/9/2012	$	63,008,147.72
4/10/2012	$	52,463,286.54
4/11/2012	$	57,549,209.30
4/12/2012	$	62,924,372.44
4/13/2012	$	63,864,705.12
4/14/2012	$	63,864,705.12
4/15/2012	$	63,864,705.12
4/16/2012	$	53,906,017.34
4/17/2012	$	66,174,118.00
4/18/2012	$	70,319,338.31
4/19/2012	$	54,355,364.30
4/20/2012	$	54,623,272.59
4/21/2012	$	54,623,272.59
4/22/2012	$	54,623,272.59
4/23/2012	$	60,460,693.98
4/24/2012	$	66,877,599.43
4/25/2012	$	49,242,879.41
4/26/2012	$	52,291,353.68
4/27/2012	$	52,944,116.15
4/28/2012	$	52,944,116.15
4/29/2012	$	52,944,116.15
4/30/2012	$	48,490,693.58
5/1/2012	$	22,611,976.45
5/2/2012	$	22,939,023.69
5/3/2012	$	26,278,910.87
5/4/2012	$	30,864,095.83
5/5/2012	$	30,864,095.83
5/6/2012	$	30,864,095.83
5/7/2012	$	33,244,666.37
5/8/2012	$	22,292,269.76
5/9/2012	$	26,384,393.63

	Cash and Short Term Investments	
5/10/2012	$	28,743,849.61
5/11/2012	$	28,843,910.18
5/12/2012	$	28,843,910.18
5/13/2012	$	28,843,910.18
5/14/2012	$	30,505,570.41
5/15/2012	$	22,027,481.14
5/16/2012	$	28,227,929.37
5/17/2012	$	9,741,914.85
5/18/2012	$	10,385,833.38
5/19/2012	$	10,385,833.38
5/20/2012	$	10,385,833.38
5/21/2012	$	9,094,960.87
5/22/2012	$	18,428,490.02
5/23/2012	$	22,297,743.14
5/24/2012	$	24,117,069.80
5/25/2012	$	3,531,614.19
5/26/2012	$	3,531,614.19
5/27/2012	$	3,531,614.19
5/28/2012	$	3,531,614.19
5/29/2012	$	6,290,221.34
5/30/2012	$	11,090,176.64
5/31/2012	$	5,387,957.96
6/1/2012	$	9,028,818.45
6/2/2012	$	9,028,818.45
6/3/2012	$	9,028,818.45
6/4/2012	$	13,293,902.95
6/5/2012	$	19,611,324.64
6/6/2012	$	23,411,359.14
6/7/2012	$	26,753,827.57
6/8/2012	$	10,253,922.38
6/9/2012	$	10,253,922.38
6/10/2012	$	10,253,922.38
6/11/2012	$	11,595,344.22
6/12/2012	$	15,947,374.65
6/13/2012	$	18,102,432.41
6/14/2012	$	20,545,924.64
6/15/2012	$	12,192,456.22
6/16/2012	$	12,192,456.22
6/17/2012	$	12,192,456.22
6/18/2012	$	15,887,244.95
6/19/2012	$	8,537,269.78
6/20/2012	$	11,671,298.20
6/21/2012	$	14,922,551.28
6/22/2012	$	19,054,472.09

	Cash and Short Term Investments	
6/23/2012	$	19,054,472.09
6/24/2012	$	19,054,472.09
6/25/2012	$	1,181,145.10
6/26/2012	$	7,789,606.13
6/27/2012	$	13,101,465.29
6/28/2012	$	24,155.74
6/29/2012	$	24,267.03
6/30/2012	$	24,267.03
7/1/2012	$	24,267.03
7/2/2012	$	335,472.47
7/3/2012	$	2,867,519.23
7/4/2012	$	2,867,519.23
7/5/2012	$	7,443,342.30
7/6/2012	$	9,626,698.25
7/7/2012	$	9,626,698.25
7/8/2012	$	9,626,698.25
7/9/2012	$	2,287,654.21
7/10/2012	$	8,706,820.30
7/11/2012	$	12,073,485.47
7/12/2012	$	16,629,773.36
7/13/2012	$	2,771,908.51
7/14/2012	$	2,771,908.51
7/15/2012	$	2,771,908.51
7/16/2012	$	356,448.29
7/17/2012	$	35,979.38
7/18/2012	$	36,350.41
7/19/2012	$	34,713.81
7/20/2012	$	57,606.34
7/21/2012	$	57,606.34
7/22/2012	$	57,606.34
7/23/2012	$	353,535.74
7/24/2012	$	8,775,551.04
7/25/2012	$	1,044,913.93
7/26/2012	$	4,217,356.16
7/27/2012	$	5,667,292.23
7/28/2012	$	5,667,292.23
7/29/2012	$	5,667,292.23
7/30/2012	$	9,220,720.79
7/31/2012	$	44,659.27
8/1/2012	$	4,694,555.53
8/2/2012	$	8,878,640.59
8/3/2012	$	12,022,215.92
8/4/2012	$	12,022,215.92
8/5/2012	$	12,022,215.92

	Cash and Short Term Investments	
8/6/2012	$	11,804,336.82
8/7/2012	$	17,130,769.06
8/8/2012	$	7,996,333.48
8/9/2012	$	14,152,062.71
8/10/2012	$	15,879,672.07
8/11/2012	$	15,879,672.07
8/12/2012	$	15,879,672.07
8/13/2012	$	22,569,265.35
8/14/2012	$	28,562,534.64
8/15/2012	$	19,556,519.68
8/16/2012	$	23,697,432.81
8/17/2012	$	24,637,404.63
8/18/2012	$	24,637,404.63
8/19/2012	$	24,637,404.63
8/20/2012	$	19,968,443.22
8/21/2012	$	29,340,974.49
8/22/2012	$	39,563,715.75
8/23/2012	$	43,396,127.73
8/24/2012	$	45,731,677.78
8/25/2012	$	45,731,677.78
8/26/2012	$	45,731,677.78
8/27/2012	$	27,863,332.94
8/28/2012	$	35,786,706.75
8/29/2012	$	39,862,774.10

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated August 28, 2012

Question No. 2.26

Responding Witness: Daniel K. Arbough

Q2.26 Refer to the Company's response to KIUC 1-34 and the fact that the Company had "cash remaining" after it financed to take advantage of low market interest rates. Please provide the daily amounts of amount of cash and short term *investments* at December 31, 2011 through the most recent date for which actual data is available.

A2.26 Attached are the daily amounts of cash and short-term investments at December 31, 2011 through August 29, 2012. The total daily cash and short term investment balances include daily loan balances made by the Company to the Utility Money Pool if applicable and exclude restricted cash.

	Cash and Short Term Investments	
12/31/2011	$	30,342,580.70
1/1/2012	$	30,342,580.70
1/2/2012	$	30,342,580.70
1/3/2012	$	27,548,596.54
1/4/2012	$	32,154,986.26
1/5/2012	$	36,033,540.48
1/6/2012	$	37,184,052.58
1/7/2012	$	37,184,052.58
1/8/2012	$	37,184,052.58
1/9/2012	$	37,476,997.42
1/10/2012	$	45,401,778.76
1/11/2012	$	48,849,486.11
1/12/2012	$	36,388,288.68
1/13/2012	$	15,184,765.04
1/14/2012	$	15,184,765.04
1/15/2012	$	15,184,765.04
1/16/2012	$	15,184,765.04
1/17/2012	$	724,618.11
1/18/2012	$	5,962,389.94
1/19/2012	$	10,560,500.08
1/20/2012	$	14,292,631.79
1/21/2012	$	14,292,631.79
1/22/2012	$	14,292,631.79
1/23/2012	$	8,875,677.98
1/24/2012	$	12,745,639.91
1/25/2012	$	209,983.00
1/26/2012	$	165,383.52
1/27/2012	$	1,537,120.75
1/28/2012	$	1,537,120.75
1/29/2012	$	1,537,120.75
1/30/2012	$	4,697,990.65
1/31/2012	$	14,575,162.74
2/1/2012	$	17,456,019.97
2/2/2012	$	21,346,563.47
2/3/2012	$	25,435,121.47
2/4/2012	$	25,435,121.47
2/5/2012	$	25,435,121.47
2/6/2012	$	27,845,541.75
2/7/2012	$	35,705,790.39
2/8/2012	$	42,088,544.55
2/9/2012	$	47,479,718.10
2/10/2012	$	47,487,127.96
2/11/2012	$	47,487,127.96

Cash and Short Term Investments

2/12/2012	$	47,487,127.96
2/13/2012	$	48,591,495.17
2/14/2012	$	54,392,348.81
2/15/2012	$	43,730,392.81
2/16/2012	$	49,860,870.70
2/17/2012	$	51,136,674.07
2/18/2012	$	51,136,674.07
2/19/2012	$	51,136,674.07
2/20/2012	$	51,136,674.07
2/21/2012	$	45,361,964.29
2/22/2012	$	48,173,969.77
2/23/2012	$	52,110,816.72
2/24/2012	$	56,567,858.65
2/25/2012	$	56,567,858.65
2/26/2012	$	56,567,858.65
2/27/2012	$	38,238,731.98
2/28/2012	$	43,247,959.63
2/29/2012	$	51,942,150.97
3/1/2012	$	54,047,611.35
3/2/2012	$	55,930,264.22
3/3/2012	$	55,930,264.22
3/4/2012	$	55,930,264.22
3/5/2012	$	56,305,997.24
3/6/2012	$	61,819,549.42
3/7/2012	$	69,536,745.15
3/8/2012	$	60,236,912.82
3/9/2012	$	59,361,034.50
3/10/2012	$	59,361,034.50
3/11/2012	$	59,361,034.50
3/12/2012	$	56,748,643.21
3/13/2012	$	63,813,890.77
3/14/2012	$	66,948,384.00
3/15/2012	$	50,525,847.79
3/16/2012	$	52,681,781.43
3/17/2012	$	52,681,781.43
3/18/2012	$	52,681,781.43
3/19/2012	$	64,568,540.73
3/20/2012	$	71,930,242.89
3/21/2012	$	77,027,219.61
3/22/2012	$	77,926,311.22
3/23/2012	$	78,793,755.57
3/24/2012	$	78,793,755.57
3/25/2012	$	78,793,755.57
3/26/2012	$	57,603,419.07

	Cash and Short Term Investments	
3/27/2012	$	62,549,557.10
3/28/2012	$	65,973,847.82
3/29/2012	$	53,341,223.87
3/30/2012	$	56,181,343.34
3/31/2012	$	56,181,343.34
4/1/2012	$	56,181,343.34
4/2/2012	$	52,552,333.84
4/3/2012	$	58,139,379.19
4/4/2012	$	60,486,607.85
4/5/2012	$	56,495,360.49
4/6/2012	$	59,248,355.92
4/7/2012	$	59,248,355.92
4/8/2012	$	59,248,355.92
4/9/2012	$	60,768,854.40
4/10/2012	$	53,474,212.54
4/11/2012	$	59,073,316.14
4/12/2012	$	61,544,443.13
4/13/2012	$	64,422,331.41
4/14/2012	$	64,422,331.41
4/15/2012	$	64,422,331.41
4/16/2012	$	44,484,177.46
4/17/2012	$	49,664,662.65
4/18/2012	$	53,987,652.79
4/19/2012	$	71,732,927.09
4/20/2012	$	67,712,072.91
4/21/2012	$	67,712,072.91
4/22/2012	$	67,712,072.91
4/23/2012	$	71,613,105.03
4/24/2012	$	76,164,078.24
4/25/2012	$	52,865,345.24
4/26/2012	$	53,879,617.93
4/27/2012	$	55,735,620.34
4/28/2012	$	55,735,620.34
4/29/2012	$	55,735,620.34
4/30/2012	$	52,630,864.34
5/1/2012	$	59,752,954.42
5/2/2012	$	60,620,372.66
5/3/2012	$	63,669,389.55
5/4/2012	$	65,014,606.69
5/5/2012	$	65,014,606.69
5/6/2012	$	65,014,606.69
5/7/2012	$	67,272,506.94
5/8/2012	$	57,529,800.65
5/9/2012	$	61,584,819.95

	Cash and Short Term Investments	
5/10/2012	$	63,661,980.65
5/11/2012	$	64,770,889.70
5/12/2012	$	64,770,889.70
5/13/2012	$	64,770,889.70
5/14/2012	$	65,496,315.93
5/15/2012	$	42,829,504.60
5/16/2012	$	46,044,257.35
5/17/2012	$	71,119,687.50
5/18/2012	$	70,241,723.24
5/19/2012	$	70,241,723.24
5/20/2012	$	70,241,723.24
5/21/2012	$	68,822,225.98
5/22/2012	$	69,904,712.53
5/23/2012	$	72,027,285.08
5/24/2012	$	71,905,797.25
5/25/2012	$	47,636,619.75
5/26/2012	$	47,636,619.75
5/27/2012	$	47,636,619.75
5/28/2012	$	47,636,619.75
5/29/2012	$	51,933,712.20
5/30/2012	$	55,621,889.52
5/31/2012	$	56,763,362.54
6/1/2012	$	52,673,530.13
6/2/2012	$	52,673,530.13
6/3/2012	$	52,673,530.13
6/4/2012	$	52,988,793.90
6/5/2012	$	57,397,481.74
6/6/2012	$	61,156,579.33
6/7/2012	$	64,661,444.39
6/8/2012	$	49,597,648.17
6/9/2012	$	49,597,648.17
6/10/2012	$	49,597,648.17
6/11/2012	$	52,052,671.96
6/12/2012	$	56,234,148.19
6/13/2012	$	58,311,195.88
6/14/2012	$	59,558,602.58
6/15/2012	$	42,074,185.76
6/16/2012	$	42,074,185.76
6/17/2012	$	42,074,185.76
6/18/2012	$	38,233,006.95
6/19/2012	$	60,344,161.24
6/20/2012	$	61,091,836.02
6/21/2012	$	59,664,930.45
6/22/2012	$	58,417,976.70

	Cash and Short Term Investments	
6/23/2012	$	58,417,976.70
6/24/2012	$	58,417,976.70
6/25/2012	$	30,875,828.20
6/26/2012	$	36,244,969.31
6/27/2012	$	40,829,567.82
6/28/2012	$	27,520,953.38
6/29/2012	$	31,390,042.70
6/30/2012	$	31,390,042.70
7/1/2012	$	31,390,042.70
7/2/2012	$	25,191,801.31
7/3/2012	$	30,180,273.82
7/4/2012	$	30,180,273.82
7/5/2012	$	33,047,227.62
7/6/2012	$	38,221,325.11
7/7/2012	$	38,221,325.11
7/8/2012	$	38,221,325.11
7/9/2012	$	39,438,547.46
7/10/2012	$	45,819,340.45
7/11/2012	$	46,989,019.99
7/12/2012	$	49,361,472.12
7/13/2012	$	38,335,699.00
7/14/2012	$	38,335,699.00
7/15/2012	$	38,335,699.00
7/16/2012	$	24,723,985.91
7/17/2012	$	27,836,202.16
7/18/2012	$	45,436,491.60
7/19/2012	$	50,162,133.24
7/20/2012	$	51,350,585.37
7/21/2012	$	51,350,585.37
7/22/2012	$	51,350,585.37
7/23/2012	$	47,976,715.90
7/24/2012	$	50,563,105.60
7/25/2012	$	29,339,099.48
7/26/2012	$	33,979,479.71
7/27/2012	$	33,593,311.81
7/28/2012	$	33,593,311.81
7/29/2012	$	33,593,311.81
7/30/2012	$	37,910,798.74
7/31/2012	$	40,521,318.07
8/1/2012	$	48,265,055.40
8/2/2012	$	51,761,104.39
8/3/2012	$	55,879,917.60
8/4/2012	$	55,879,917.60
8/5/2012	$	55,879,917.60

		Cash and Short Term Investments
8/6/2012	$	56,348,006.37
8/7/2012	$	59,968,122.47
8/8/2012	$	53,788,059.21
8/9/2012	$	57,852,314.96
8/10/2012	$	57,800,045.42
8/11/2012	$	57,800,045.42
8/12/2012	$	57,800,045.42
8/13/2012	$	59,769,893.69
8/14/2012	$	63,901,880.74
8/15/2012	$	52,596,970.89
8/16/2012	$	50,858,810.97
8/17/2012	$	60,147,436.43
8/18/2012	$	60,147,436.43
8/19/2012	$	60,147,436.43
8/20/2012	$	58,033,707.94
8/21/2012	$	65,677,788.14
8/22/2012	$	60,403,770.09
8/23/2012	$	63,535,406.68
8/24/2012	$	60,573,199.20
8/25/2012	$	60,573,199.20
8/26/2012	$	60,573,199.20
8/27/2012	$	39,468,841.95
8/28/2012	$	45,707,423.42
8/29/2012	$	48,406,959.97

EXHIBIT ____ (LK-25)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-35

Responding Witness: Daniel K. Arbough

Q1-35. Refer to page 7 lines 10-15 of Mr. Arbough's Direct Testimony. Please explain why the Company did not have short term debt outstanding at March 31, 2012, given the various available sources of short term debt cited.

A1-35. As discussed in the response to Question No. 34, the Company uses short-term debt to finance working capital and to fund capital expenditures until the balance is sufficient enough to justify the issuance of long-term debt. The response to Question No. 34 also referenced the possibility of issuing debt in advance of needs for capital expenditures. KU did not have any short-term debt outstanding at March 31, 2012 because the Company took advantage of attractive markets in November 2010 and replaced all of its long-term and short-term intercompany debt with long-term debt and had cash remaining to use for future working capital and capital expenditure needs.

It was prudent to borrow the additional funds at the time of the issuance in November 2010 because the interest rates were at very low levels and the Company was not certain the low rates would last until KU had needs sufficient enough to justify another long-term bond. The interest rate on the intercompany loans in place prior to the debt issuance was approximately 5.50% whereas the average rate on the new bonds was approximately 3.98%, and this reduction was realized in spite of extending the average maturity of the debt portfolio by over 10 years.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-34

Responding Witness: Daniel K. Arbough

Q1-34. Refer to page 7 lines 9-13 of Mr. Arbough's Direct Testimony. Please explain why the Company did not have short term debt outstanding at March 31, 2012, given the various available sources of short term debt cited.

A1-34. As discussed in the response to Question No. 33, the Company uses short-term debt to finance working capital and to fund capital expenditures until the balance is sufficient enough to justify the issuance of long-term debt. The response to Question No. 33 also referenced the possibility of issuing debt in advance of needs for capital expenditures. LG&E did not have any short-term debt outstanding at March 31, 2012 because the Company took advantage of attractive markets in November 2010 and replaced all of its long-term and short-term intercompany debt with long-term debt and had cash remaining to use for future working capital and capital expenditure needs.

It was prudent to borrow the additional funds at the time of the issuance in November 2010 because the interest rates were at very low levels and the Company was not certain the low rates would last until LG&E had needs sufficient enough to justify another long-term bond. The interest rate on the intercompany loans in place prior to the debt issuance was approximately 5.50% whereas the average rate on the new bonds was approximately 3.56%, and this reduction was realized in spite of extending the average maturity of the debt portfolio by over 8 years.

EXHIBIT ____ (LK-26)

KIUC Adjustments to KU Capitalization and Cost of Capital
Case No. 2012-00221
Test Year Ending March 31, 2012

I. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Per Book Balance	KU Proforma Adjustments	KU Adjusted Total Co. Capitalization	KU Kentucky Jurisdictional Factor	KU Jurisdictional Capitalization	Capital Ratio	Remove Environmental Compliance Plans	Adjusted KU Jurisdictional Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	-		-	87.52%	-	0.00%		-	0.00%	0.41%	0.00%	0.00%	-
Long Term Debt	1,840,750,374	(797,948)	1,839,952,426	87.52%	1,610,326,363	46.30%	(85,030,505)	1,525,295,858	46.30%	3.69%	1.71%	1.72%	56,607,746
Common Equity	2,138,484,751	(4,085,474)	2,134,399,277	87.52%	1,868,026,247	53.70%	(98,636,561)	1,769,389,686	53.70%	11.00%	5.91%	9.39%	309,418,797
Total Capital	3,979,235,125	(4,883,422)	3,974,351,703		3,478,352,610	100.00%	(183,667,066)	3,294,685,544	100.00%		7.62%	11.11%	366,026,542

II. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Capitalization by Short Term Investments in Money Pool as of March 31, 2012

	Adjusted KU Jurisdictional Capitalization	KIUC Proforma Adjustment 1	KU Kentucky Jurisdictional Factor	KIUC Jurisdictional Proforma Adjustment 1	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	-	87.52%	-	-	0.00%	0.00%	0.41%	0.00%	0.00%	-	-
Long Term Debt	1,525,295,858	(23,428,052)	87.52%	(20,504,231)	1,504,791,627	46.30%	46.30%	3.69%	1.71%	1.72%	55,846,757	(760,989)
Common Equity	1,769,389,686	(27,217,450)	87.52%	(23,820,712)	1,745,568,974	53.70%	53.70%	11.00%	5.91%	9.39%	305,253,300	(4,165,497)
Total Capital	3,294,685,544	(50,645,502)		(44,324,943)	3,250,360,601	100.00%	100.00%		7.62%	11.11%	361,100,057	(4,926,485)

III. KU Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 9.2%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	0.00%	0.41%	0.00%	0.00%	-	-
Long Term Debt	1,504,791,627	46.30%	3.69%	1.71%	1.72%	55,846,757	-
Common Equity	1,745,568,974	53.70%	9.20%	4.94%	7.85%	255,302,760	(49,950,540)
Total Capital	3,250,360,601	100.00%		6.65%	9.57%	311,149,517	(49,950,540)

EXHIBIT ____ (LK-27)

KIUC Adjustments to LG&E (Electric) Capitalization and Cost of Capital
Case No. 2012-00221
Test Year Ending March 31, 2012

I. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Per Book Balance	Capital Ratio	LG&E Kentucky Electric Factor	LG&E Electric Capitalization	LG&E Adjustments to Capitalization	Adjusted LG&E Electric Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	-	0.00%	79.01%	-	-	-	0.00%	0.41%	0.00%	0.00%	-
Long Term Debt	1,105,705,507	44.36%	79.01%	873,617,921	7,385,010	881,002,931	44.36%	3.81%	1.69%	1.70%	33,746,044
Common Equity	1,387,034,687	55.64%	79.01%	1,095,896,106	9,262,895	1,105,159,001	55.64%	11.00%	6.12%	9.82%	195,110,625
Total Capital	2,492,740,194	100.00%		1,969,514,027	16,647,905	1,986,161,932	100.00%		7.81%	11.52%	228,856,669

II. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Reducing Capitalization by Short Term Investments in Money Pool as of March 31, 2012

	Adjusted LG&E Electric Capitalization	KIUC Proforma Adjustment	LG&E Kentucky Electric Factor	KIUC Electric Proforma Adjustment 1		KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	-	79.01%	-		-	0.00%	0.41%	0.00%	0.00%	-	-
Long Term Debt	881,002,931	(24,920,375)	79.01%	(19,689,588)		861,313,343	44.36%	3.81%	1.69%	1.70%	32,991,852	(754,192)
Common Equity	1,105,159,001	(31,260,968)	79.01%	(24,699,291)		1,080,459,710	55.64%	11.00%	6.12%	9.82%	190,750,081	(4,360,544)
Total Capital	1,986,161,932	(56,181,343)		(44,388,879)		1,941,773,053	100.00%		7.81%	11.52%	223,741,933	(5,114,736)

III. LG&E (Electric) Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 9.2%.

	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	0.00%	0.41%	0.00%	0.00%	-	-
Long Term Debt	861,313,343	44.36%	3.81%	1.69%	1.70%	32,991,852	-
Common Equity	1,080,459,710	55.64%	9.20%	5.12%	8.22%	159,536,431	(31,213,650)
Total Capital	1,941,773,053	100.00%		6.81%	9.92%	192,528,283	(31,213,650)

EXHIBIT ____ (LK-28)

KENTUCKY UTILITIES COMPANY

CASE NO. 2012-00221

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-34

Responding Witness: Daniel K. Arbough

Q1-34. Please describe how the Company uses short term debt, i.e., to finance construction prior to refinancing with permanent capital, short term working capital, etc.

A1-34. KU funds capital projects with short-term debt, typically in the form of money pool loans, commercial paper or loans under bank lines of credit, until the Company believes the short-term balance will be permanently in the range of $250 million or above. At that time, the Company will issue long-term debt to reduce the amount of outstanding short-term debt. If market conditions are attractive and the Company believes long-term rates will increase before the short-term debt balances reach $250 million, the Company may choose to issue long-term bonds in advance of the need for the cash to fund capital projects.

The Company also uses short-term debt to fund various working capital needs. The Company believes it is critical to maintain sufficient liquidity availability in its financing arrangements.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated July 31, 2012

Question No. 1-33

Responding Witness: Daniel K. Arbough

Q1-33. Please describe how the Company uses short term debt, i.e., to finance construction prior to refinancing with permanent capital, short term working capital, etc.

A1-33. LG&E funds capital projects with short-term debt, typically in the form of money pool loans, commercial paper or loans under bank lines of credit, until the Company believes the short-term balance will be permanently in the range of $250 million or above. At that time, the Company will issue long-term debt to reduce the amount of outstanding short-term debt. If market conditions are attractive and the Company believes long-term rates will increase before the short-term debt balances reach $250 million, the Company may choose to issue long-term bonds in advance of the need for the cash to fund capital projects.

The Company also uses short-term debt to fund various working capital needs. The Company believes it is critical to maintain sufficient liquidity availability in its financing arrangements.